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FINAL PROJECT REPORT

Integrated CHP Using Ultra-Low NOx Supplemental Firing

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Prepared by: Gas Technology Institute

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PREFACE

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Integrated CHP Using Ultra-Low NOx Supplemental Firing is the final report for the Integrated CHP Using Ultra-Low NOx Supplemental Firing project contract number PNG-07-006 conducted by Gas Technology Institute. The information from this project contributes to Energy Research and Development Division's Advanced Generation Program.

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ABSTRACT

The Gas Technology Institute, along with its partners Integrated CHP Systems Corporation and Cannon Boiler Works Incorporated, developed and demonstrated an ultra-low-nitrogen oxide Flexible Combined Heat and Power system that packaged a state-of-the-art Capstone C65 gas microturbine and Johnston PFXX100 boiler with an innovative natural gas-fired supplemental burner. Supplemental burners add heat as needed in response to facility demand, which increased energy efficiency, but typically raised exhaust nitrogen oxide levels, degrading local air quality unless a costly and complicated catalytic treatment system was added. The Flexible Combined Heat and Power system increased energy efficiency and achieved the 2007 California Air Resource Board distributed generation emissions standards for nitrogen oxides, carbon monoxide, and total hydrocarbons without catalytic exhaust gas treatment. The key to this breakthrough performance was a simple and reliable burner design which utilized staged combustion with engineered internal recirculation. This ultra-low-nitrogen oxide burner system successfully used turbine exhaust as an oxidizer, while achieving high efficiencies and low emissions. In tests at its laboratory facilities in Des Plaines, Illinois, the Gas Technology Institute validated the ability of the system to achieve emissions of nitrogen oxides, carbon monoxide, and total hydrocarbons below the CARB criteria. The Flexible Combined Heat and Power system was installed at the field demonstration site, Inland Empire Foods, in Riverside, California to verify performance of the technology in an applied environment. The resulting combined heat and power package promises to make combined heat and power implementation more attractive, mitigate greenhouse gas emissions, improve the competitiveness of California industry, and improve the reliability of the electricity supply.

Keywords:
Combined heat and power, Distributed generation, Microturbine, Duct burner, Low nitrogen oxide burner, Supplemental firing, Turbine exhaust gas

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EXECUTIVE SUMMARY

Introduction

Gas turbines are engines driven by the pressure of burning compressed air and fuel. Gas turbines have a number of beneficial features that have led to their widespread application for combined heat and power (CHP), including their relatively simple design, low capital cost per kilowatt, low maintenance requirements, and lower emissions compared to reciprocating engines. However, because of the need to operate at high excess air (225-550 percent), exhaust losses from gas turbine-based CHP systems are relatively high, and addressing this issue offers an opportunity for further cost savings. A common approach to recoup some of the energy loss is through the use of supplemental burners such as duct or parallel burners to combust additional fuel in the oxygen-rich turbine exhaust gas (TEG) and to raise the temperature for better downstream heat recovery in a boiler. For example, with natural gas as fuel and a final flue gas temperature of 275°F, reducing the excess air from 355 percent to 15 percent decreases the stack loss from 46 percent to 17 percent on a High Heating Value (HHV) basis. HHV refers to the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C.

However, even with duct or parallel burner designs with lower emissions of nitrous oxides (NOx)—also known as low-NOx burners—CHP systems have difficulty meeting the 2007 Fossil Fuel Emissions Standard established by the California Air Resources Board (CARB) without exhaust gas cleanup by selective catalytic reduction (SCR) or by other post-combustion processes. SCR technology causes NOx reduction reactions to take place in an oxidizing atmosphere by using ammonia, which reacts with NOx to convert the pollutants into nitrogen, water and tiny amounts of carbon dioxide, all of which are natural elements common to everyday air. Consequently, there was a need to develop integrated CHP systems that properly match a power generator (turbine), a low emission supplemental burner, and a waste heat user (boiler). These integrated systems would help improve energy efficiency, meet future federal and state clean air regulations, and take full advantage of the benefits of gas turbines.

Project Purpose

The goal of this project was testing and deploying a CHP system that could deliver power and steam while meeting emissions standards for certain pollutants. The specific objective of the project was to successfully deploy Gas Technology Institute's (GTI's) Flexible Combined Heat and Power (FlexCHP) system. Successful deployment means that the system could provide power and steam while holding NOx, carbon monoxide, (CO), and total hydrocarbon (THC) emissions below the California Air Resources Board (CARB) 2007 emissions standards for distributed generation systems. The system, designated as FlexCHP-65, combined a Capstone C65 microturbine, a GTI-developed supplemental ultra-low-NOx (ULN) burner, and a 100 horsepower heat recovery boiler by Johnston Boiler.

The supplemental UNL burner was successfully tested on a simulator, and a data acquisition system was used to collect data. The supplemental burner was then evaluated to see if the concentrations of NOx, CO, and THC emissions remained constant. The CHP system was first installed and tested at GTI for a laboratory demonstration. The system was then tested at a demonstration site in California. Basic requirements for implementing the system at the host site included electric and steam interconnections, structural review of the site physical plant, addition of a new stack, mechanical additions and modifications, and compliance with local permits.

Project Results

The supplemental ULN burner is an innovative combustion approach that promises industrial end-users a dramatic increase in energy efficiency and reduced air emissions. The efficiency of microturbine-based distributed generation systems is a function of the ability of the system to recover and use the waste heat in the exhaust of the microturbine. The major advantages of a supplemental burner coupled with a microturbine were an increase in total system efficiency due to lowering exhaust oxygen levels from 17-18 percent by volume to 3-5 percent by volume and an increase in the quality of the heat produced from the microturbine exhaust. By employing auxiliary burners in the exhaust of the microturbine, the amount and temperature of the available heat became independent from the amount of electricity produced. This advantage enables more systems utilizing waste heat recovery from turbines to be designed, manufactured and sold. The supplemental burner has outstanding emission characteristics, which will provide a competitive edge over existing low-NOx systems in the fast developing area of CHP applications for installations where low emissions is a performance requirement.

Combining the supplemental ULN burner technology with state-of-the-art gas turbines allowed for the development of a system which achieved the CARB 2007 emissions criteria for distributed generation units without the use of end-of-pipe cleanup technology such as SCR. The supplemental burner, designed by GTI and installed between the gas turbine and heat recovery boiler, combusted natural gas using the TEG as an oxidant, just as current duct burners do. Integrating the supplemental burner technology with a gas turbine created the additional benefit of reduced NOx emissions from the combined system. The additional fuel combustion added very little NOx and effectively completed combustion, keeping CO at very low levels.

The supplemental ULN burner demonstrated increased energy efficiency while meeting the CARB 2007 emissions criteria without the use of catalytic exhaust gas treatment. The key to this breakthrough performance is a simple and reliable advanced burner design with engineered internal recirculation. The burner exposed NOx and NOx precursors to a low temperature zone, resulting in a lower NOx content per unit of heat input than that of the original TEG. Preliminary laboratory testing with a supplemental ULN burner using the exhaust from a 65-kW Capstone microturbine proved that NOx was as low as 0.035 lb per megawatt hour (MWh), which is half of the required 0.07 lb/MWh. Further field testing at the host site facility, Inland Empire Foods, verified this key performance measure in an applied setting. The FlexCHP system demonstrated significant improvements in emissions and efficiency performance, as compared to the microturbine operating alone. System efficiency was increased from 23.6 percent to 82.4 percent or 84.2 percent based upon the measurement method, by recovering heat from the turbine exhaust to generate steam at rates up to 2,140 lb/hour. Under full load conditions, NOx, CO, and THC emissions were reduced by 45 percent, 97 percent, and 78 percent, respectively. The resulting CHP packages promise to make CHP implementation more attractive, mitigate greenhouse gas emissions, improve the competitiveness of the industry, and improve the reliability of electricity.

The FlexCHP system will provide CHP users with a highly efficient source of on-site heat for use with boilers and absorption chillers. The technology is environmentally superior and cost-competitive compared to state-of-the-art duct burner technology available on the market. The developed technical approach can be expanded to other combustion applications using TEG or preheated air as combustion air in situations where low combustion emissions are required.

Project Benefits

This project has successfully designed and demonstrated a high-efficiency CHP system capable of using a small to medium sized gas turbine for new and retrofit applications in the range of 30-5500 kW, which meets the CARB 2007 emissions standard. Targeted for boilers and absorption chillers, the technology will reduce the capital cost of distributed generation CHP systems by 10-25 percent. This will make these systems more acceptable to small to medium size (10 MW or less) industrial plants and commercial buildings, representing a large portion of the available California market. The project supported California's policy goals by increasing efficiency in all of the state's energy sectors, encouraged the development of environmentally-sound CHP resources and distributed generation projects, and supported the reduction of greenhouse gases.

INTRODUCTION

Gas turbines have a number of beneficial features that have led to their widespread application for combined heat and power (CHP), including their relatively simple design, low capital cost per kilowatt, low maintenance requirements, and lower emissions compared to reciprocating engines. However, because of the need to operate at high excess air (225-550 percent), exhaust losses from gas turbine based CHP systems are relatively high and offer an opportunity for further cost savings. A common approach to recoup some of the energy loss is through the use of supplemental burners (i.e. duct or parallel burners) to combust additional fuel in the oxygen-rich Turbine Exhaust Gas (TEG) and to raise the temperature for better downstream heat recovery in a boiler. For example, with natural gas as fuel and a final flue gas temperature of 275°F, reducing the excess air from 355 percent to 15 percent decreases the stack loss from 46 percent to 17 percent on a High Heating Value (HHV) basis.

However, even with low-NOx duct or parallel burner designs, CHP systems have difficulty meeting the 2007 Fossil Fuel Emissions Standard, without exhaust gas cleanup by Selective Catalytic Reduction (SCR) or by other post combustion processes. Consequently, there is a need to develop integrated CHP packages that properly match a power generator (turbine), a low emission supplemental burner, and a waste heat user (boiler) to improve energy efficiency and still meet future clean air requirements. This requires a burner that produces very low NOx emissions even with high-temperature TEG (600-1000°F) as the oxidant.

Gas Technology Institute (GTI's) research and development on supplemental ULN burners for gas turbine based CHP has achieved promising results. The innovative burner can fire natural gas with TEG and meet the emissions standard. The key to the design is staged combustion with engineered internal recirculation that exposes NOx and NOx precursors to a low temperature zone. Figure 1 shows the conceptual design of the supplemental burner. Natural gas partially mixes with the TEG before entering the combustion zone. The velocity of the gas/TEG mixture through several nozzles is sufficient to create a reduced pressure zone at the base of the primary nozzle exit, which induces flow from the exit of the primary zone. Inside the recirculation insert, the products of partial combustion flow back to the root of the flame, as indicated by the curved arrows. These combustion products contain hydrogen species, which improves combustion stability in the primary zone, allowing combustion at relatively low stoichiometric ratios. Additional TEG is injected through a pipe, which is located at the center of the burner downstream of the primary zone. Mixing of the TEG with the combustion products from the primary zone is critical to the design of a very-low NOx burner. If the gaseous mixture is well mixed, there are no high concentrations of oxygen, which could cause hot spots and generate NOx. The recirculation insert also radiates heat to the cold boiler walls and allows products of partial combustion to cool before flowing to the secondary combustion zone and back to the root of the flame, cooling and stabilizing it.

In earlier developmental work, a concept burner was fired up to 2.2 million Btu/h on TEG from a Capstone 60-kW microturbine. Figure 2 shows the general layout of the laboratory test set up at GTI. The microturbine was exhausted to the supplemental ULN burner and then fired into a 20-inch diameter boiler simulator.

Figure 1: Supplemental ULN Burner Concept

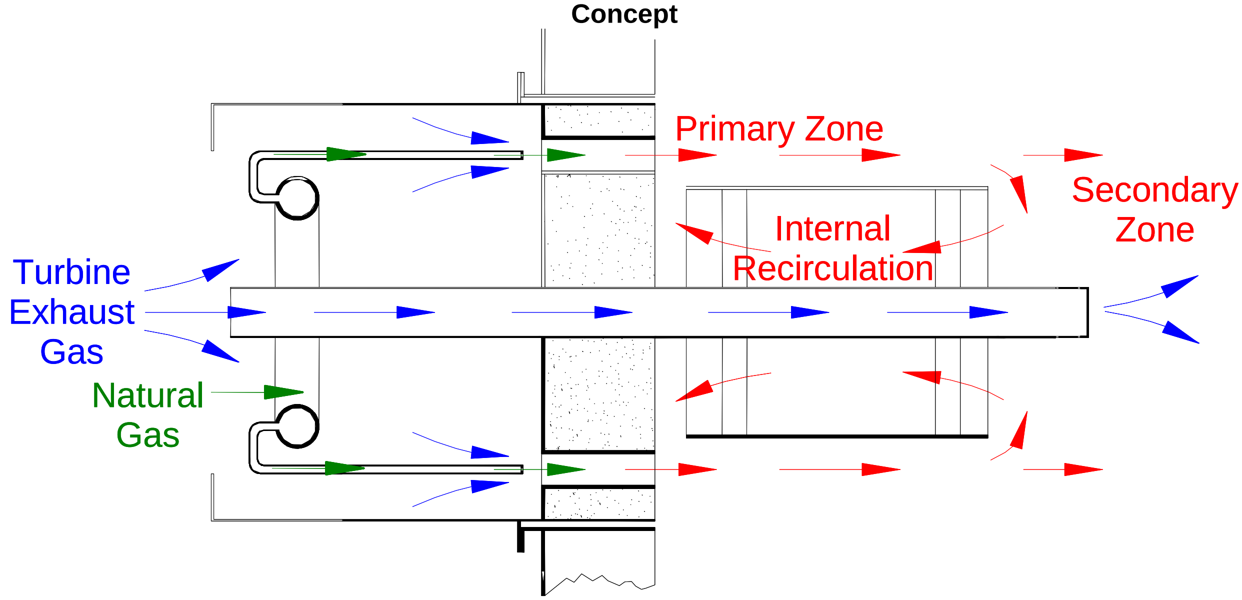
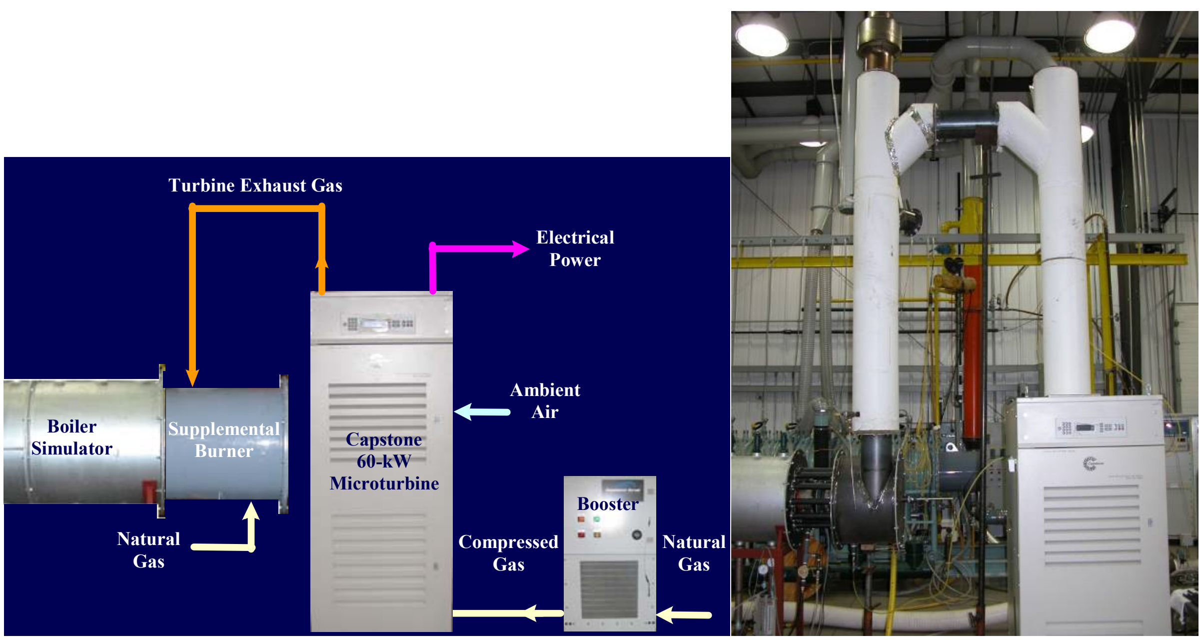


Figure 2: Layout of Microturbine Supplemental ULN Burner



Based on test results, the burner is capable of adding significant thermal energy to the TEG to generate steam. . On a volume per volume basis, stack NOx emissions, after supplemental firing, are lower than NOx emissions from the gas turbine, even in the case of the ultra-low NOx emissions (3.4 ppmv on a 15 percent O_2 basis)[1] from the Capstone microturbine. In Table 1, the data shows a reduction in NOx emissions of 35 percent which are below those produced by the gas turbine alone. These data demonstrate that the combined turbine and supplemental burner can comfortably meet the 0.07 lb/MWh target for CHP systems. CO emissions are also within the 2007 Fossil Fuel Emissions target of 0.10 lb/MWh because in all tests CO was below 10 ppmv which corresponds to approximately 0.05 lb/MWh. System efficiency with the burner increases from about 38 percent to 70-80 percent, depending on the size of the burner and heat recovery unit (boiler or absorption chiller). Based on these data, gas-fired turbines or microturbines with up to 9 ppmv NOx (~0.43 lb/MWh) in the TEG can be combined with the supplemental burner at the current level of development and reduce stack NOx below 0.07 lb/MWh. This will include the Solar Mercury 50 and Taurus 60 model employing catalytic combustion.

Table 1: Data from Laboratory Testing of Supplemental ULN Burner with Capstone Microturbine

	Microturbine	Microturbine + Supplemental ULN Burner
Turbine Output, kW	50	50
Burner Fuel Input, million Btu/h	--	2.11
O_2, vol percent	17.8	8.1
NOx, ppmv	3.4	2.2
CO, ppmv	9	5
NOx Reduction, percent	--	35.2

[1] All emissions are corrected to 15 percent oxygen unless otherwise noted.

CHAPTER 1: Value of the Technology

The value of the technology is to allow gas turbine based CHP applications to meet the most stringent California air quality rules without post combustion flue gas cleanup such as SCR. One of the more near-term attractive applications of the supplemental ULN burner is for CHP installations using Solar's Mercury 50 recuperated 4.3-MW turbine, which is designed for 5 ppmv NOx in simple cycle operation. In spite of its very low NOx rating, the Mercury 50 cannot currently meet the 2007 Fossil Fuel Emissions Standard without catalytic flue gas treatment. However, based on our laboratory results, we project that the Mercury 50 can meet these emissions goals with the supplemental ULN burner in an integrated CHP system while also increasing overall system efficiency. Figure 3 shows how the predicted NOx, measured as lb/MWh output, varies with the level of NOx reduction for a Mercury 50 combined with a 50 million Btu/h supplemental burner. In this case, any NOx reduction greater than about 10 percent is sufficient to satisfy the 0.07 lb/MWh standard.

The predicted performance of the same supplemental burner in a Mercury 50 installation is also shown in Table 2 along with laboratory performance data from the Capstone microturbine test unit, in this case based on a NOx reduction of 35 percent.

Figure 3: Variation of Output-Based NOx Emissions with Supplemental ULN Burner Effectiveness

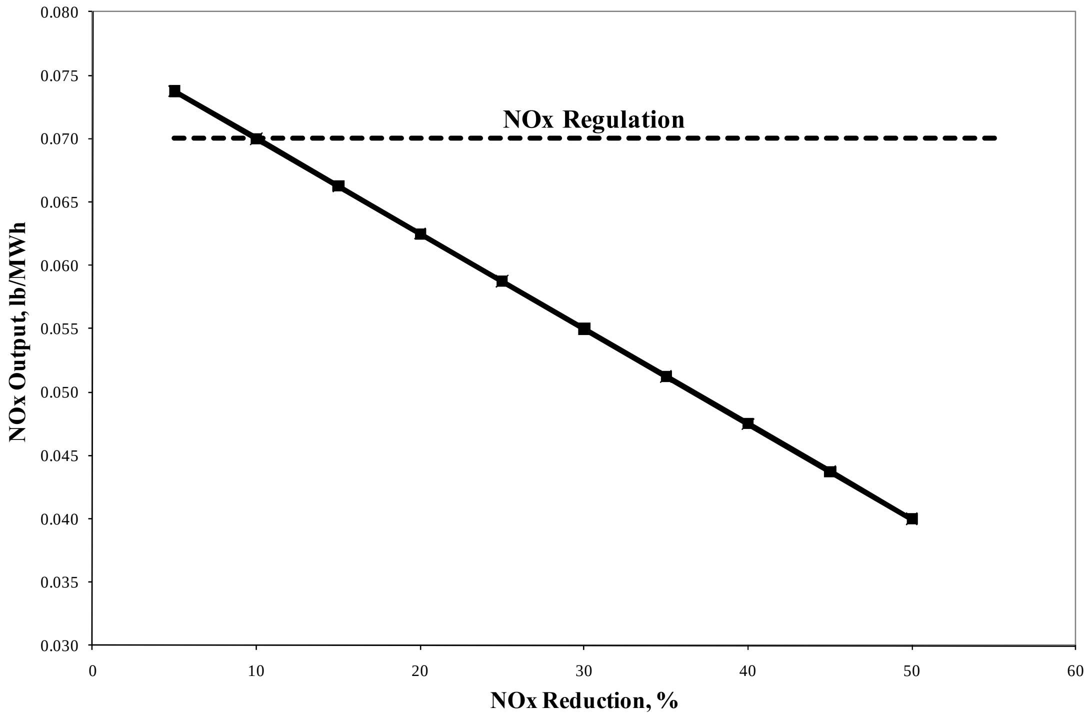


Table 2: Comparison of Laboratory Data and Predicted Performance for the Mercury 50

	Capstone 60-kW (GTI Laboratory)	Mercury 50 (Predicted)
Turbine Output, kW	50	4,387
Turbine Fuel Input, million Btu/h	0.68	43.74
Turbine Efficiency, percent (HHV)	28.0	38.0
TEG O_2, vol percent	17.8	16.4
TEG NOx, ppmv	3.4	5.0
Burner Fuel Input, million Btu/h	1.95	50.0
Burner Exhaust O_2, vol percent	8.1	11.0
Burner Exhaust NOx, ppmv	2.2	3.2
NOx Reduction, percent	35.2	35.2
Heat Recovered in Boiler, million Btu/h	1.96	58.7
Overall CHP Efficiency, percent (HHV)	80.0	74.9

Meeting emissions targets, however, is not the only challenge to proponents of CHP. The installed cost of CHP systems is a major barrier to implementing this energy-saving approach for small to medium-size industrial plants and commercial buildings. Achieving this output based emissions level with existing gas turbines or those that are expected to enter the market is challenging. A supplemental burner using advanced design to reduce NOx from gas-fired TEG will be a real breakthrough in bringing cost-effective CHP solutions to the market. This will present an alternative solution and eliminate the need for costly SCR.

CHAPTER 2: Development

2.1 Turbine Exhaust Gas Generation

As a continuation of the earlier developmental work, the burner technology was scaled up to 7.5 million Btu/h. At this firing capacity, the microturbine was not capable of generating sufficient TEG at temperature to simulate the Mercury 50 gas turbine (see Table 3). At full load, the exhaust gas composition from the Solar Mercury 50 has 16.4 percent O_2 and 5 ppmv NOx[2] at 705°F.

Table 3: Summary of Mercury 50 Emissions Data

Solar Mercury 50				
Turbine Load, percent	25	50	75	100
Exhaust Temperature, °F	637	666	681	705
O_2, vol percent	17.8	17.2	16.7	16.4
NOx, ppmv	--	5	5	5
CO_2, vol percent	1.8	2.2	2.4	2.6

2.2 Test Setup

The supplemental ULN burner was designed and evaluated up to 7.5 million Btu/h on a 40-inch water cooled simulator. The TEG was simulated with a mixture of flue gases from a low NOx auxiliary burner and dilution air post combustion to closely match the exhaust gas constituents and exhaust temperature of a Solar Mercury 50 gas turbine.

The simulated turbine exhaust Gas (STEG) generator is shown in Figure 4. The low NOx auxiliary burner was fired on a 20-inch, water cooled, chamber that produced the flue gases. It then cooled them before entering a mixing section that introduced the dilution air. The water cooled combustion chamber was sized appropriately to absorb enough heat from the flue gases

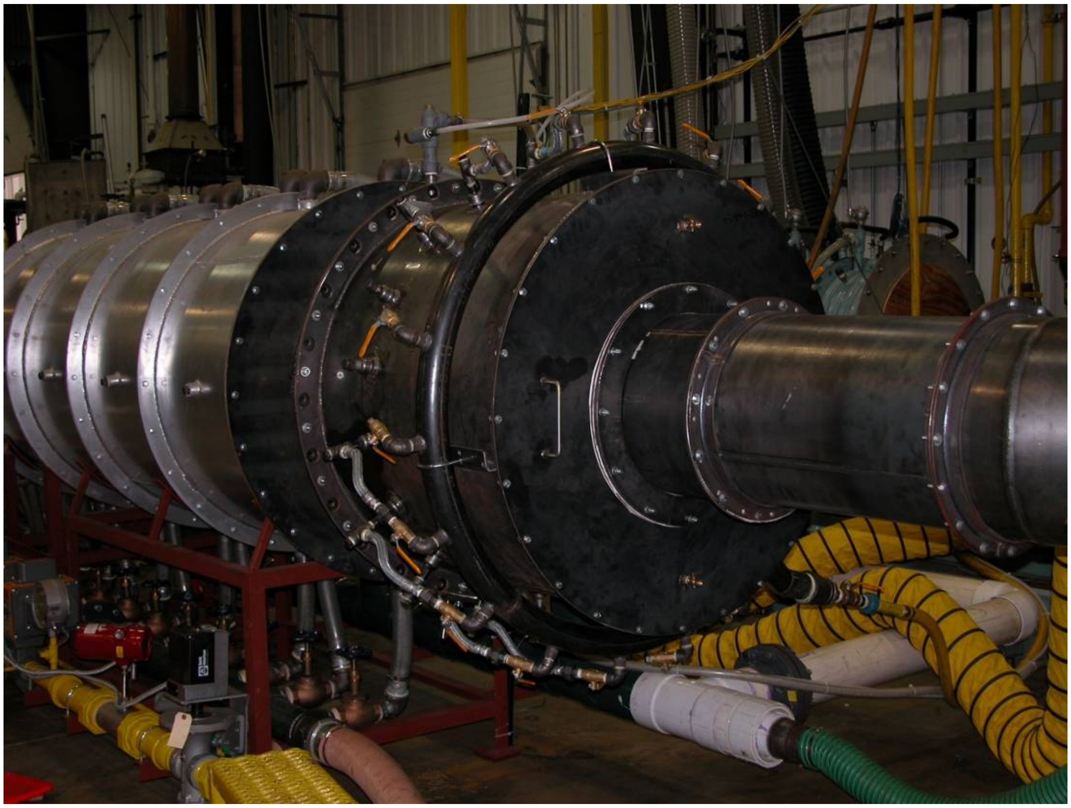
[2] All emissions are corrected to 15 percent oxygen unless otherwise noted.

so the mixture temperature matched closely to the Mercury 50. Mass flows and temperatures were monitored closely during all testing and recorded in the data acquisition system.

The 7.5 million Btu/h supplemental ULN burners are shown in Figure 5. The STEG enters the burner axially through a 16-inch duct. The STEG is directed to either the primary or secondary zone of the burner via a sliding damper. Prior to the primary zone combustion, STEG is introduced with natural gas at the nozzle entrance and then mixing occurs over a short linear distance and enters the combustion chamber for ignition. Downstream of the sliding damper is a butterfly damper assembly to enhance the control and distribution of STEG to the secondary zone of the burner. As this damper is further closed, additional STEG is directed to the primary zone of the burner. The natural gas supply manifold is located external to the burner to allow for on-the-fly adjustments during the test campaign. Various ports are available to collect gas constituency, pressure, and temperature within the burner.

Figure 4: Auxiliary Combustor to Generate STEG

Figure 5: 7.5 million Btu/h Supplemental ULN Burner



The supplemental ULN burner was installed on a 40-inch diameter simulator consisting of heat recovery and flue gas exit sections. The heat recovery section is constructed from four modules as shown in Figure 5. The four 24 inch-long modules are identical from the burner side and flanged on each side for flexibility. Each module has a water jacket type cooling system in which the city water enters from the bottom and exits from the top to drain. The entire simulator is mounted on one stand and can be easily moved. Gas composition and temperature sampling ports were installed downstream of the heat recovery sections in the stationary flue gas exit sections. Emissions measurements obtained at this location are representative of stack data. Further downstream is a water-cooled damper used to adjust pressure in the combustion chamber. Additional ductwork leading to the stack consists of 30-inch diameter steel ducting lined with 6-inch thick composite refractory. The ducting is mounted on stands for support.

2.3 Natural Gas Supply

The natural gas supply line to the burner is standard 2-inch pipe with a double block-and-bleed valve arrangement. The components on the natural gas supply includes a Roots flow meter, manual shutoff valve, gas pressure regulator, supply pressure gauge, Sierra mass flow meter, manual shutoff valve, supply pressure gauge, gas pressure regulator, low-pressure switch, safety solenoid valve, vent solenoid valve, second safety solenoid valve, and a high-pressure switch. The data from the Sierra mass flow meter is recorded directly to the data acquisition system. The gas supply line supplies gas to a North American flow control valve that meters natural gas to the supplemental burner. This natural gas train is connected to the burner inlet by a 1 inch diameter flexible hose. Although the natural gas supply manifold is located external to the burner, natural gas is combined with STEG internal to the burner.

The auxiliary burner, used to generate STEG, is independently supplied with natural gas and combustion air via modular combustion control skids. Each skid is a self-contained system that controls and meters flow to a selected combustion device.

2.4 Analytical Equipment and Measurements

A data acquisition system was used to collect data continuously and at specified points during evaluation of the supplemental ULN burner. The major flow rate measurements recorded were combustion air, natural gas, and diluent air for the auxiliary combustor; and natural gas for the supplemental burner. Appropriate furnace operation parameters and NO/NO_x, CO, CO_2, THC, and O_2 emissions from the auxiliary burner and downstream of the supplemental burner in the exhaust gas were measured. A type "K" thermocouple was installed to measure STEG and supplemental burner exit gas temperatures.

The natural gas and combustion air flow rates were measured using Sierra thermal mass flow meters. The static pressure at the combustion chamber exit, burner windbox, and fuel manifold were measured with a manometer.

The exhaust gas sample was drawn through a 1/4-inch-OD by 3-foot-long, stainless steel probe. The gas sample was withdrawn using oil-less vacuum pumps and passed through sample conditioning trains, which consist of a water trap to remove any condensate and a membrane dryer for removing the moisture. The sample conditioning trains are located near the probe and are followed downstream by Teflon sample lines to deliver the gas sample to various gas analyzers through a sample flow control and distribution panel. The control panel (shown in Figure 6) facilitates easy switching between gas sampling and instrument calibration.

Figure 6: Panel Mounted Emissions Monitors

The flue gas composition was measured using continuous emission gas monitors. The following gas analyzers were utilized:

- Thermo Environmental Model 42C chemiluminescence NOx analyzer
- Rosemount Analytical Model 880A dispersed infrared carbon monoxide analyzer
- Rosemount Analytical Model 880A dispersed infrared carbon dioxide analyzer
- Rosemount Analytical Model 400A flame ionization total hydrocarbons analyzer
- Rosemount Analytical Model 755R paramagnetic oxygen analyzer.

All of the instruments were calibrated prior to each test campaign using pure nitrogen to establish the "zero" and an appropriate span gas to set the "gain." An analysis of the certified span gas mixture used during the evaluation follows:

NOx: 7.4 ppmv

CO (low): 149 ppmv

CO (high): 24.93 percent

CO_2: 18.0 percent

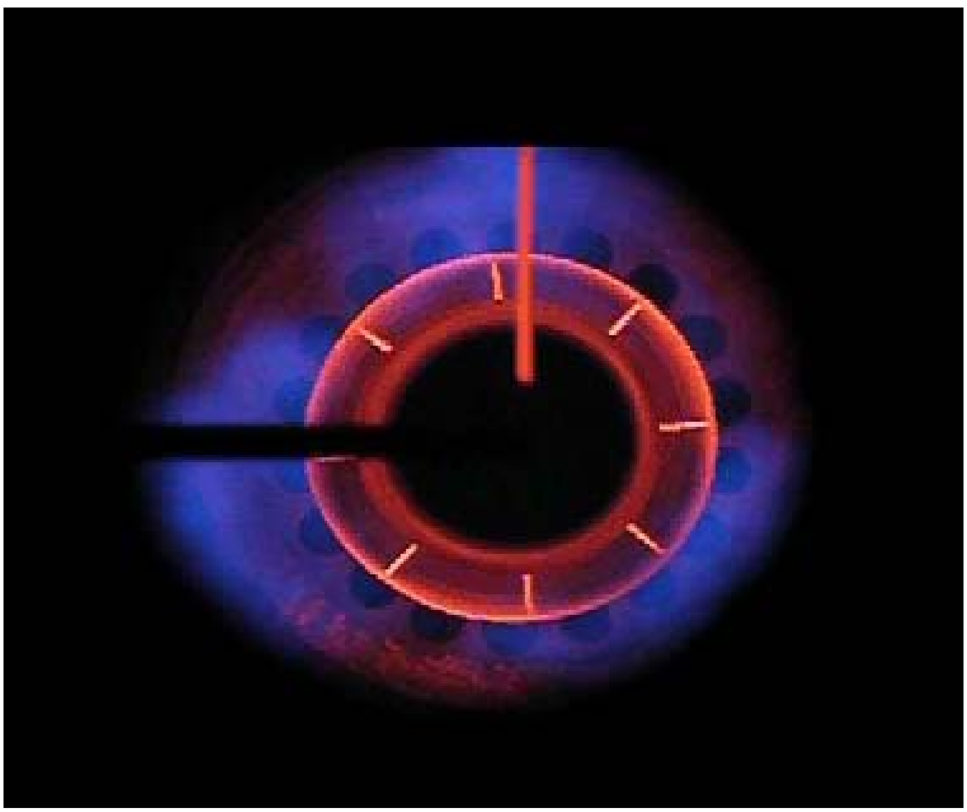
THC: 341 ppmv

O_2: 3.92 percent

2.5 Results

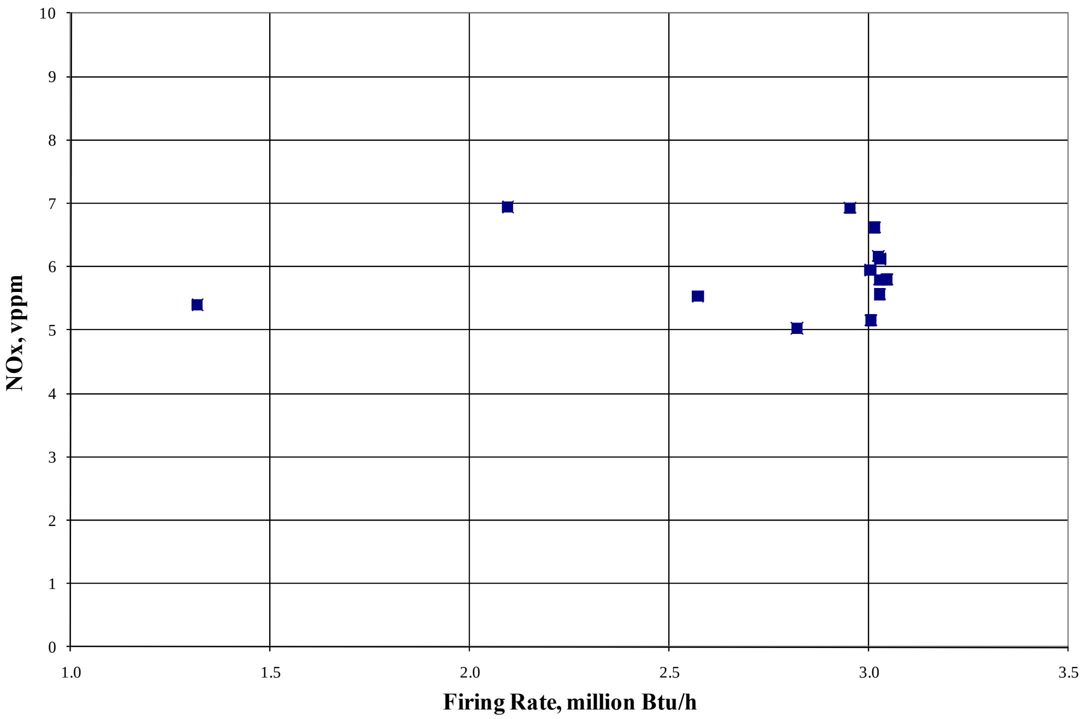
The 7.5 million Btu/h supplemental ULN burner was tested on a 40-inch diameter boiler simulator. The main parameters varied were the firing rate, the number of primary nozzles, and the ratio of STEG between the primary/secondary zones. Figure 7 shows the supplemental burner flame looking from the exit of the simulator back towards the burner.

Figure 7: Supplemental ULN Burner Flame at 7 million Btu/h



An auxiliary burner, with a three to one turndown ratio, was used to generate flue gases that were mixed together with dilution air. The resulting mixture closely matched the gas composition and temperature of the Mercury 50 gas turbine across its firing range. NOx emissions from the STEG were consistent throughout the firing range (see Figure 8).

Figure 8: NOx Emissions Across the Firing Range



The supplemental ULN burner was evaluated with natural gas heat inputs ranging from 1.9 to 7.1 million Btu/h. Figure 9 shows NOx emissions and oxygen concentrations as a function of burner firing rate. The data is representative of the Mercury 50 gas turbine operating at 100 percent load (oxygen concentration 16.4 percent). A dashed line represents the average NOx concentration measured in the STEG across the firing range. In all cases, the NOx concentration measured downstream of the supplemental burner; was the same or lower, than the NOx concentration measured in the STEG. Overall NOx concentrations decreased as the burner firing rate increased. Although not shown, at all test points CO and THC emissions remained below 50 ppmv. The oxygen concentration varied over the firing range while maintaining a fixed amount of STEG.

Testing was also conducted at conditions representative of the Mercury 50 gas turbine operating at 75 percent load (oxygen concentration 16.7 percent). Figure 10 shows the results do follow the trend established at 100 percent load. The average NOx concentration measured in the STEG across the firing range for this test campaign is represented by a dashed line. In all cases, the NOx concentration measured downstream of the supplemental burner is the same or lower, than the NOx concentration measured in the STEG. Overall NOx concentrations decreased as the burner firing rate increased and; although not shown, CO and THC emissions at all points remained below 50 ppmv.

Figure 9: Supplemental ULN Burner Test Results Gas Turbine Load at 100%

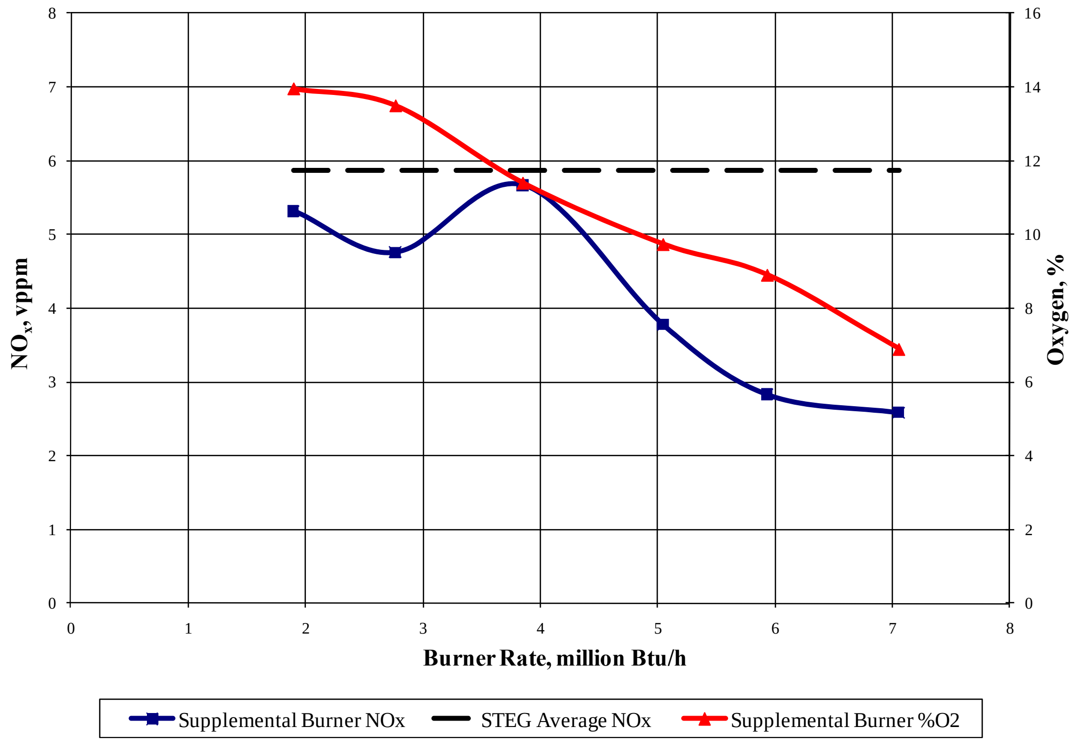
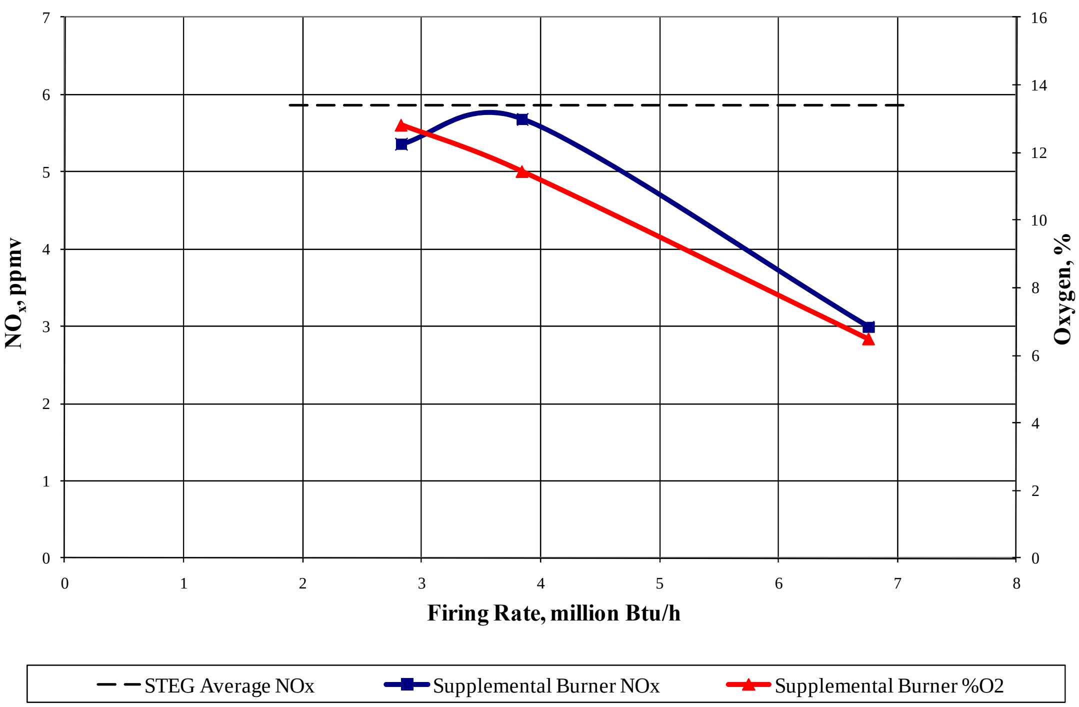


Figure 10: Supplemental ULN Burner Test Results Gas Turbine Load at 75%



Inherent to the burner design is a center tube that acts as a bypass and allows the burner to handle larger amounts of TEG than a typical burner. The center tube simply diverts the excess gases around the combustion zone. A test campaign was conducted at 100 percent gas turbine load to investigate the effect of oxygen concentration on supplemental burner NOx production. The quantity of STEG was varied to the supplemental burner; which in turn, varied the oxygen concentration at the exit of the supplemental burner. The results are plotted in Figure 11 and reveals there is a negligible effect on NOx production at different oxygen concentrations. This is an important point because, as the gas turbine changes load, the supplemental burner will be forced to handle varying oxygen concentrations.

The maximum pressure drop through the burner remained below 2.3 in wc. The pressure data is plotted in Figure 12. The natural gas supply pressure ranged from 3.0 psig at low fire rate to 28.6 psig at high fire rate.

Figure 11: Supplemental ULN Burner Exhaust Oxygen Concentration

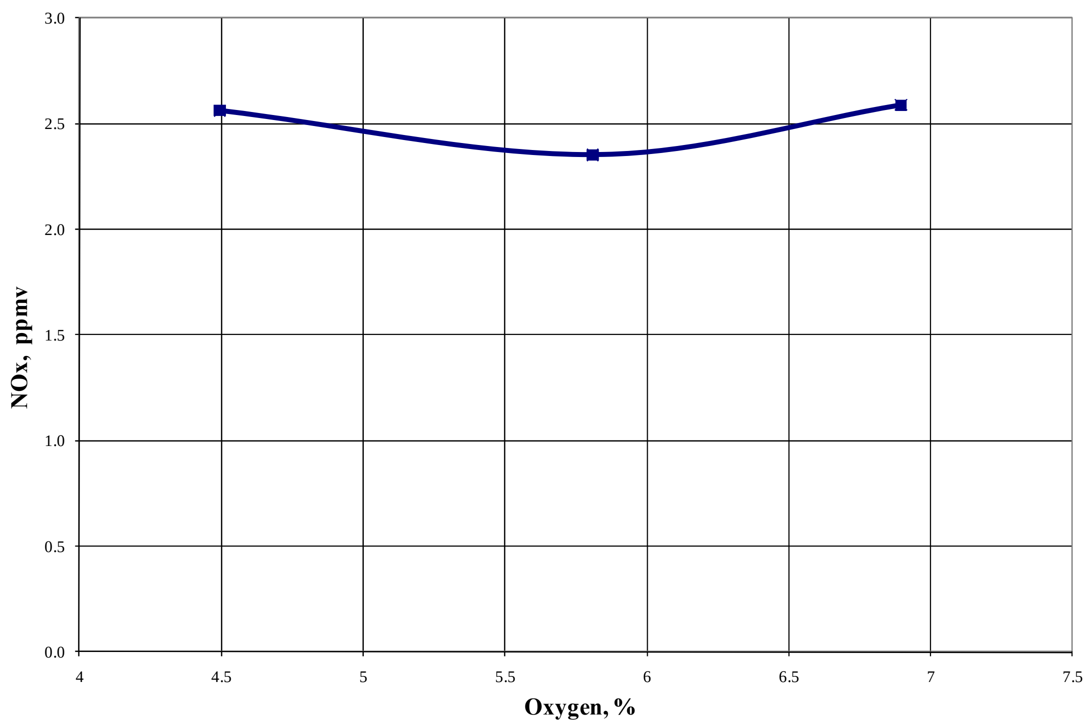
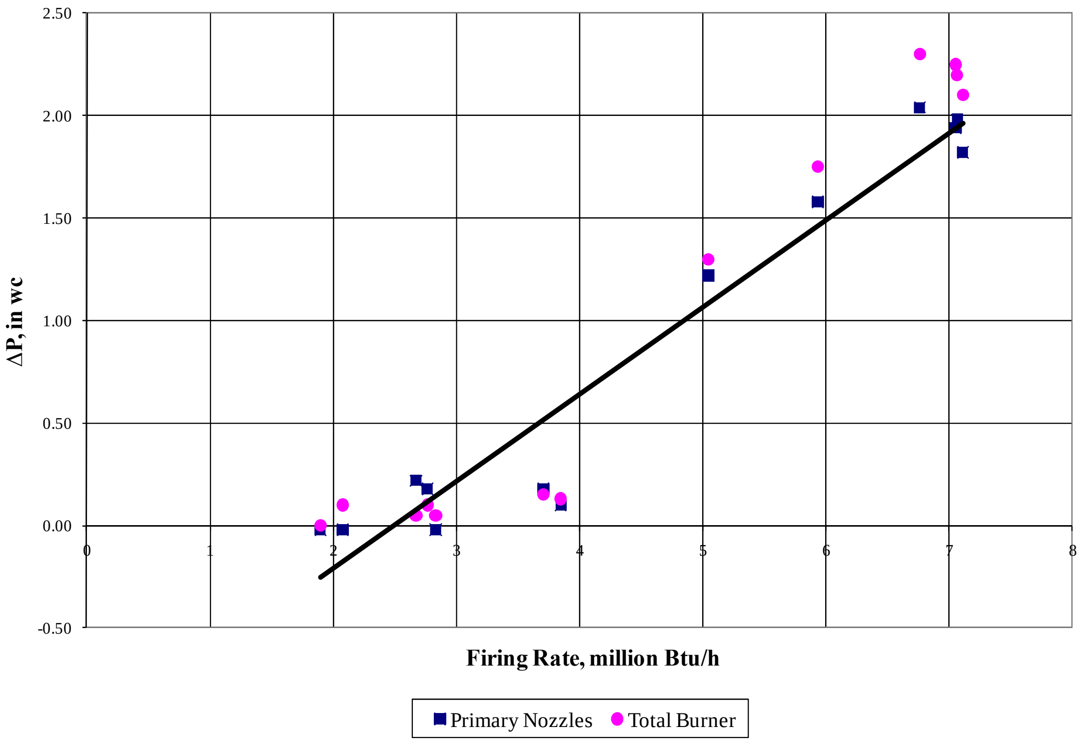


Figure 12: Supplemental ULN Burner Pressure



CHAPTER 3: CHP System

The FlexCHP system combines a Capstone C65 microturbine, a supplemental ULN burner, and a 100 HP heat recovery boiler by Johnston Boiler Company. The microturbine provides power to the facility and the exhaust is ducted to the supplemental ULN burner. The burner is connected to the boiler which provides steam and is interconnected to the existing steam header.

3.1 Host Site

The site for demonstration of the FlexCHP system was Inland Empire Foods located in Riverside, California. Since 1985 Inland Empire Foods has been manufacturing legume ingredients with a focus on flavor and functionality. They are passionate about advancing the culinary and nutritional benefits of legumes and believe in manufacturing all natural, wholesome legume ingredients for their customers worldwide. Electric power is provided by Southern California Edison which is the local municipal power utility and natural gas is supplied by Southern California Gas Company.

3.2 Site Loads

Loads at the host site consist of the electric load and the steam load, as described below.

3.2.1 Electric Load

Based on process equipment provided by Inland Empire Foods, all of the electricity generated by the FlexCHP system will be consumed on site. The peak facility demand is 229 kW. The project team determined that a 65 kW turbine will have a sufficiently high load factor through the process run.

3.2.2 Steam Load

The existing plant operates on steam and uses three boilers, one food grade for cooking and two units for drying. The food grade unit is normally separated but can act as backup by opening an isolation valve for the two drying units that have a common steam header. The existing boilers have a water treatment system with condensate from the drying units being returned to the two non-food grade boilers. During normal production runs, the steam requirements for the facility were assessed to be in the range of 1.5 to 3 million Btu/h which is consistent with gas usage data.

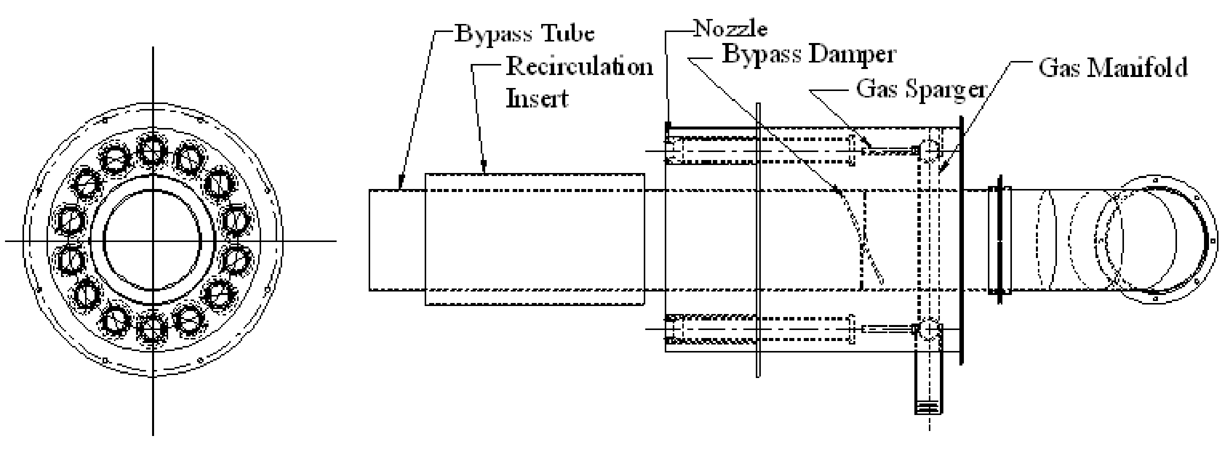
3.3 Microturbine

The microturbine is a Capstone C65 natural gas fired 65 kW unit. The "FlexCHP-65 " is the name used to describe the complete CHP package, which includes the Capstone C65 microturbine, supplemental ULN burner, and Johnston Boiler Company two-pass firetube boiler. Major turbine engine components include a compressor, a recuperator (exhaust gas heat exchanger), a combustor, a turbine, and a generator. The turbine engine is air-cooled and supported on air-lubricated compliant foil bearings. The compressor impeller, turbine rotor, and generator rotor are mounted on a single shaft, which comprises the only moving part in the engine. A gas booster shall also be required to increase the available gas pressure to meet the microturbine requirements.

3.4 Burner and Boiler

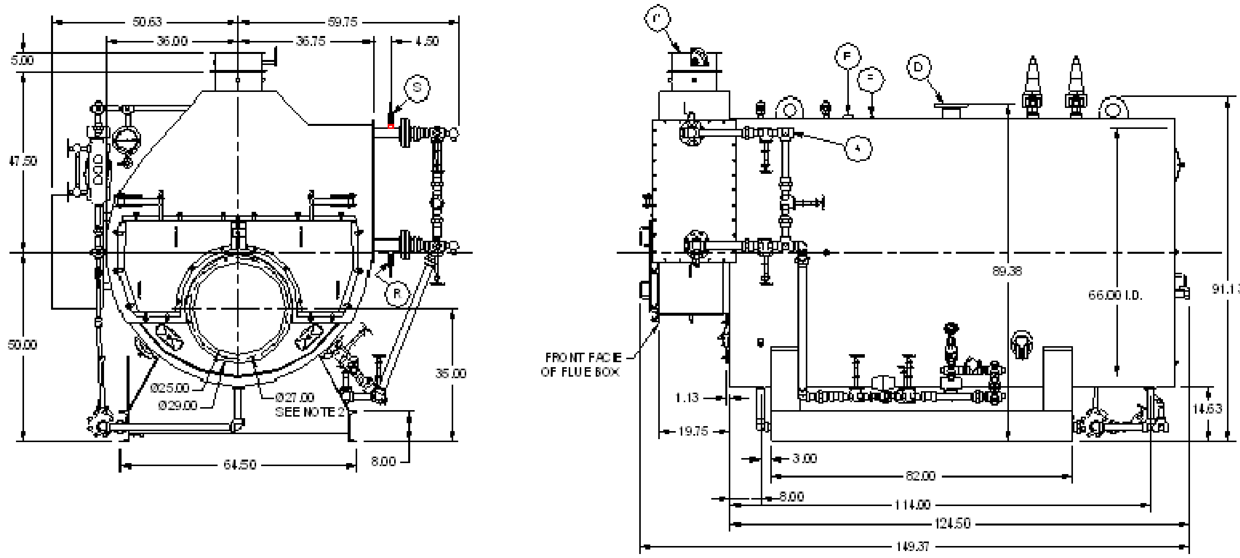
The supplemental ULN burner is an innovative design developed by GTI that is intended to use the exhaust gas from the microturbine as feed air and to combust natural gas to raise the exhaust temperature. The resulting emissions from the boiler stack are intended to meet or exceed the CARB 2007 Fossil Fuel Emissions Standard requirements for NOx, CO, and THC without catalytic exhaust gas treatment. The supplemental burner will connect to the new steam boiler and an exhaust duct from the microturbine will supply the supplemental burner with TEG. Figure 13 shows a cross-section of the supplemental burner for this demonstration.

Figure 13: Supplemental ULN Burner Cross-Section



The boiler is a standard firetube boiler design adapted to meet the needs of the project. The boiler will be designed to provide 90 psig steam to the plant. Figure 14 shows the 100 HP boiler from the front and side. The existing boiler plant has a feedwater system that includes chemical treatment. A new line will be brought from this feedwater system to the new boiler.

Figure 14: Firetube Boiler Perspective



3.5 Interconnection Plan

The FlexCHP-65 system is a steam and power system operating from natural gas. The electric power is interconnected on the customer side of the utility meter and is distributed to the process load through the existing power distribution system. The microturbine generator is connected in parallel with the Southern California Edison grid and is provided with a pulse-output power meter to assure some level of constant import from the grid. This provides reverse power flow protection and enables the system to operate as a 'non export' system. Current sensors are required at the meter, which is interconnected with the microturbine panel. When the import level drops to a preset margin, the microturbine will automatically be turned down. The system is not designed to provide emergency back-up power and so does not have black start capability. It is anticipated that the site will consume all power generated.

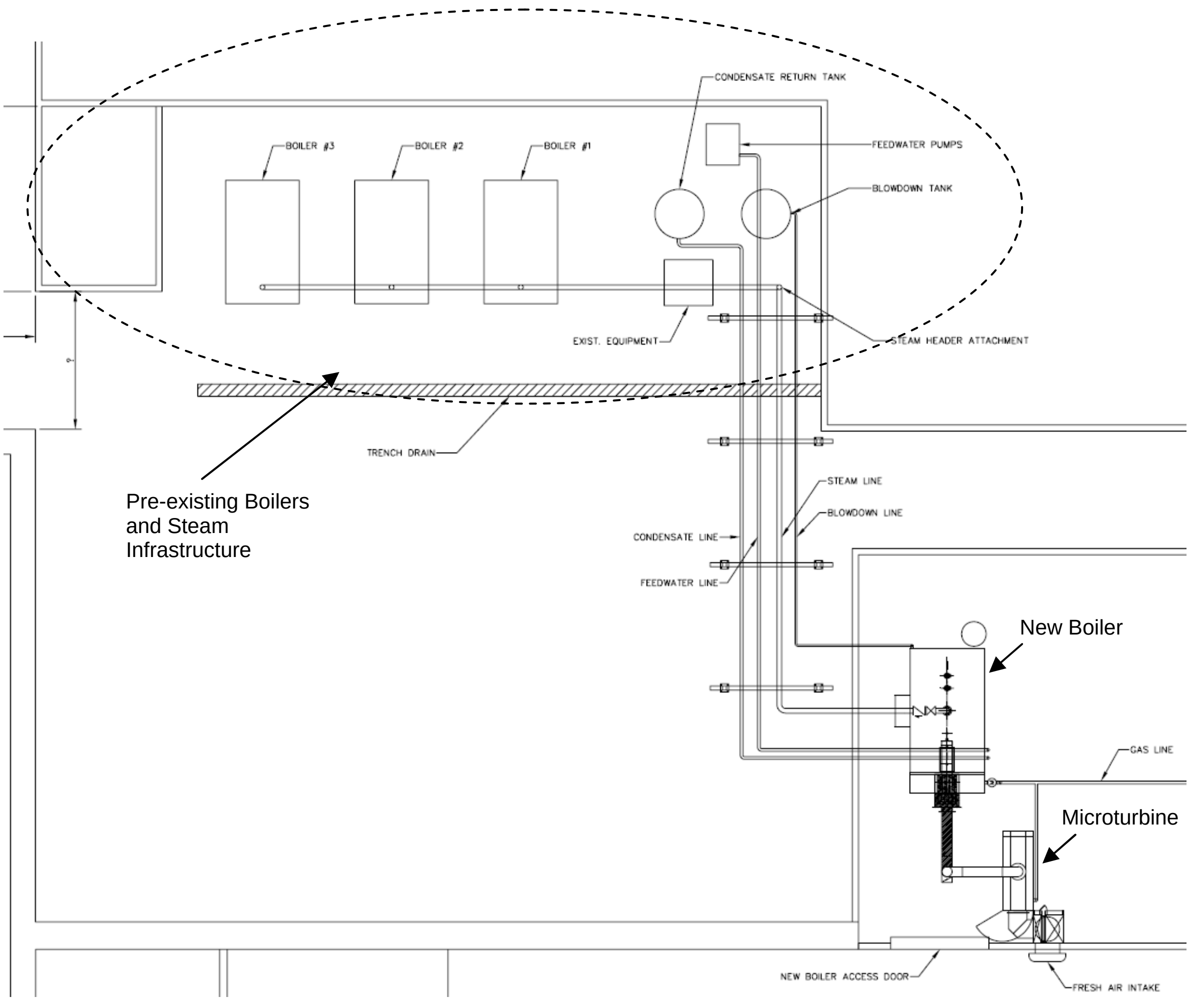
The steam output from the FlexCHP-65 system is interconnected with the existing steam header at 90 psig, which is the same operating pressure as the existing boilers. Steam from the new boiler is fed to a common plant header. A steam pressure control valve and other required safety devices are installed in the steam line.

The plant requires natural gas to both the supplemental ULN burner and the microturbine. A new line branches off the supply line, complete with a new gas meter at the CHP location. One leg with a new pressure relief valve supplies 9 psig pressure of gas to the microturbine gas booster and the other leg has a new pressure relief valve supplying approximately 9 psig pressure gas to the supplemental ULN burner.

3.6 Equipment Layout Plan

Figure 15 indicates the layout of the CHP plant equipment relative to the existing plant and services.

Figure 15: CHP Plant Layout



3.7 Project Requirements

Basic requirements for implementation of the system at the host site included electric and steam interconnections, structural review of the site physical plant to assess the need for any modifications to accommodate the new system or to accommodate local code requirements, addition of a new stack for the system, mechanical additions and modifications, and compliance with local permits. These are summarized below.

3.7.1 Electric Interconnection

As the FlexCHP-65 system only generates a portion of the electric power required during processing, the electric output of the system is connected in parallel to the grid. In order to meet the safety requirements of the local utility (Southern California Edison), a non-exporting control will be employed to prevent inadvertent export of power by turning down the microturbine, when the plant load is less than the turbine output plus the minimum import requirement.

3.7.2 Steam Interconnection

The process steam loads are connected to a common header which is supplied by the two existing firetube boilers used for drying. The new system steam output is brought to the same header and fed to the process load at a common pressure of 90 psig.

3.7.3 Structural

The location for the new CHP plant is inside the older building on the existing concrete slab. Ten inch wide stainless steel foot pads were installed on the boiler skids to help distribute the weight load and eliminate the need for modifying the concrete floor.

A set of hangers were fabricated and installed along the ceiling of the plant to hold the steam lines running between the new system and existing boiler infrastructure. Two exhaust stacks were installed: one for the boiler exhaust and a second for the turbine exhaust pressure relief. Both stacks penetrate the building horizontally and then run vertically up the side of the building above the roof line.

3.7.4 Electrical

A new 100 A, 480 V switch is located in the new panel to provide the power required for operation of the CHP plant. A new feeder runs to the microturbine. A second 30 A circuit and circuit breaker feed power to the boiler control panel. This feeder terminates on four terminals in the boiler control panel.

3.7.5 Mechanical

The CHP plant requires makeup water to the new boiler as well as a natural gas supply to the microturbine and supplemental ULN burner. In addition, the contractor installed a new steam header between the boiler and the existing steam header with two new isolation valves and pressure relief lines and a boiler blowdown line. The steam line was insulated with fiberglass insulation (where indoors), integral with self-locking PVC jacket.

Figure 16: Steam piping schematic

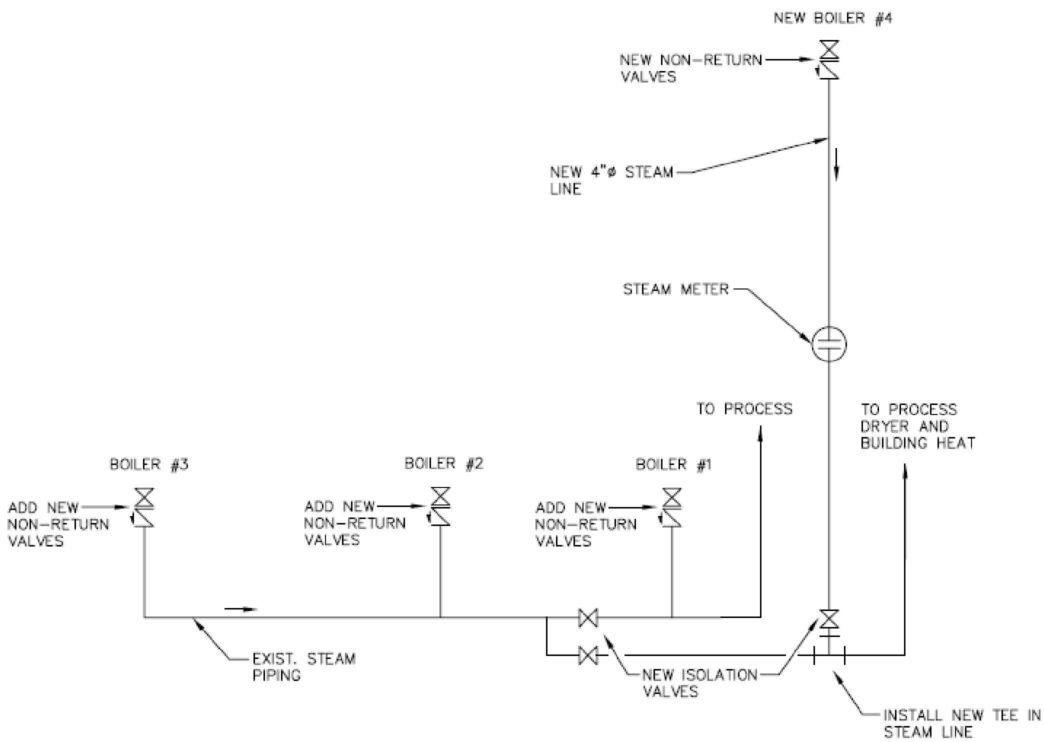
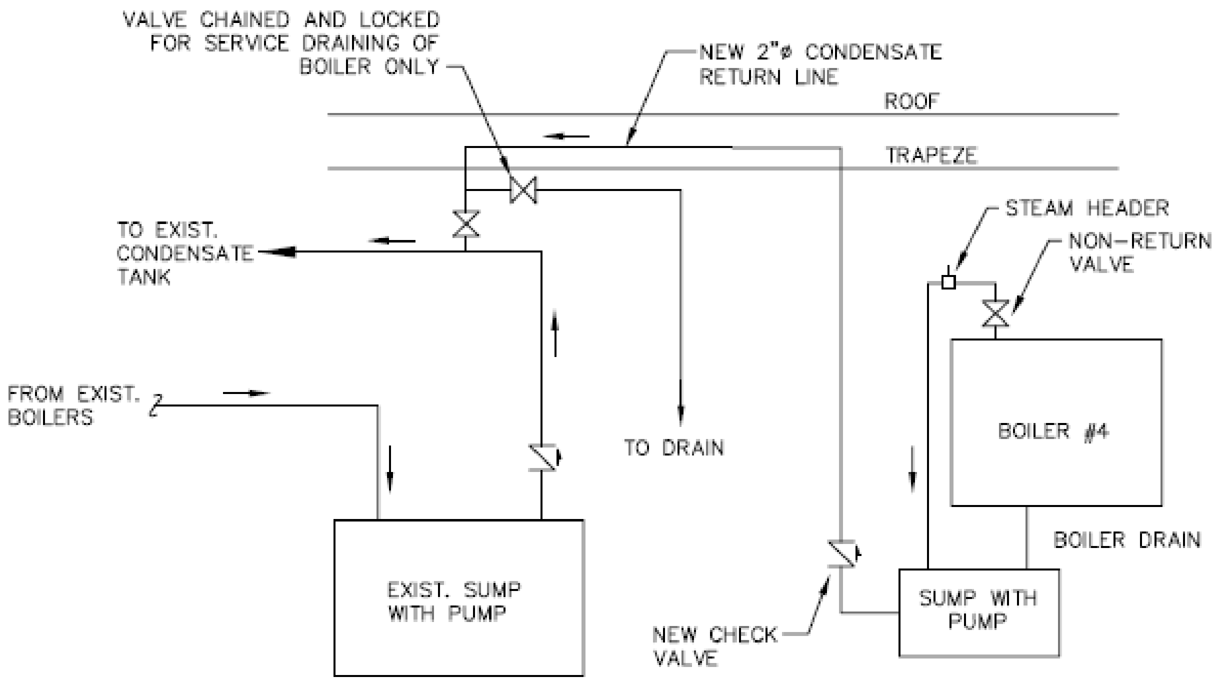


Figure 17: Condensate return and boiler drain piping schematic.



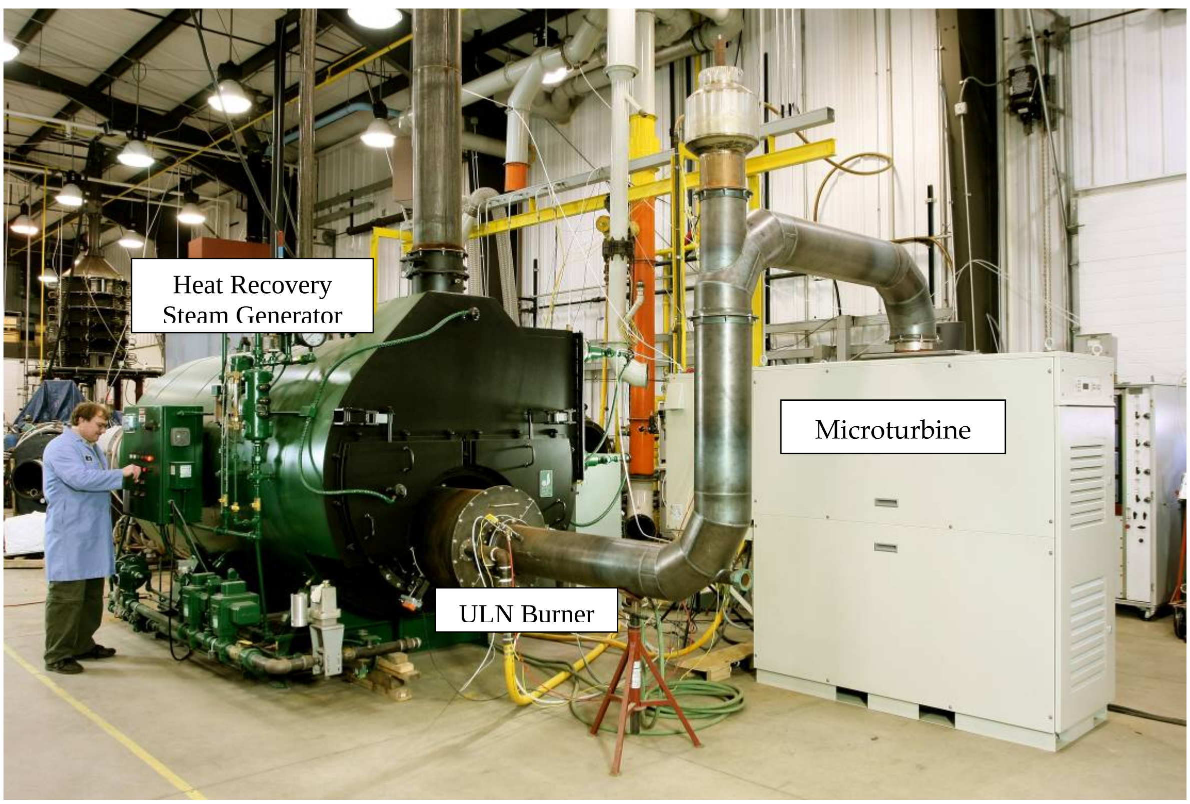
3.7.6 Permitting

An air quality permit was required for the FlexCHP-65 system from the South Coast Air Quality Management District (SCAQMD) and an interconnection permit from Southern California Edison. Because the FlexCHP-65 packaged system does not fall clearly into any of the SCAQMD equipment categories, documentation outlining the operating characteristics of the system was supplied along with the air quality permit application. This documentation greatly helped to facilitate discussions with SCAQMD and satisfy their requests for additional information, allowing for the permit application to be processed in a timely manner.

CHAPTER 4: Demonstration

In preparation for the field demonstration, the complete FlexCHP system including the 65 kW microturbine (Capstone C65) and heat recovery steam generator (Johnston PFXX100 boiler) was installed and evaluated at GTI. This laboratory demonstration allowed for additional refinements in the burner technology to provide optimal operating conditions with the selected power generator and heat recovery steam generator. Figure 18 shows the complete system as installed at GTI.

Figure 18: FlexCHP 65 System in Laboratory Testing



Successful optimization of the supplemental ULN burner has allowed for performance data to be collected to ensure compliance with the CARB 2007 emissions criteria. These results were critical when applying for the South Coast Air Quality Management District air quality permit to operate at the demonstration host site. Following the laboratory demonstration, the field evaluation of the FlexCHP system at Inland Empire Foods provided the opportunity to demonstrate the performance of the technology under the demands of real world conditions. The test methods and results for both the laboratory and field demonstrations are described below.

4.1 Laboratory Demonstration Test Methods

The laboratory test methods focused on verifying the performance of the supplemental burner in terms of complying with CARB 2007 emissions criteria. The initial test matrix evaluated the burner performance at varying firing rates and varying combustion zone oxygen contents. Variation in these parameters alone proved insufficient to achieve burner performance in compliance with CARB 2007 emissions criteria. As a result, several contingency variables were evaluated including nozzle designs, fuel/air mixing designs, and sleeve designs until satisfactory burner performance was achieved.

Exhaust gas emissions were measured in accordance with Association of State Energy Research and Technology Transfer Institutions (ASERTTI) protocols, where applicable. Gas samples were drawn through a 1/4-inch-OD stainless steel probe using an oil-less vacuum pump and passed through a sample conditioning train, which consisted of water traps to remove any condensate and a membrane dryer for removing moisture. Figure 19 shows the sampling instrumentation setup. The sample conditioning train was located near the probe and was followed downstream by Teflon sample lines to deliver the gas samples to the various gas analyzers through a sample flow control and distribution panel. The control panel facilitated easy switching between gas sampling and instrument calibration without disruption in the flow rates. An internal pump inside the analyzer was used to draw a dry sample at a flow rate of approximately 0.5 L/min. The sample lines were shut down at approximately 1-hour intervals to drain condensate from the water traps and purge lines with dry grade nitrogen. The instruments used for measuring the final stack gas composition are listed in Table 4.

Table 4: Emissions Analyzers for Stack Exhaust Gas Composition

Constituent	Manufacturer	Model	Method
Oxide of Nitrogen	Thermo Environmental	42C	Chemiluminescence
Carbon Monoxide	Emerson	X-Stream GP	Non-dispersed infrared
Carbon Dioxide	Rosemount Analytical	880A	Non-dispersed infrared
Total	Rosemount Analytical	400A	Flame ionization total

Hydrocarbons			hydrocarbons
Oxygen	Emerson	X-Stream GP	Paramagnetic

Gas compositions of the microturbine exhaust and the primary combustion zone products were also measured in accordance with the same methodology outlined above. The instruments used in these measurements are listed in Table 5.

Table 5: Emissions Analyzers for Microturbine Exhaust and ULN Combustion Zone Gas Composition

Constituent	Manufacturer	Model	Method
Oxide of Nitrogen	Horiba	PG250	Chemiluminescence
Carbon Monoxide	Horiba	PG250	Non-dispersed infrared
Carbon Dioxide	Horiba	PG250	Non-dispersed infrared
Oxygen	Horiba	PG250	Paramagnetic

Figure 19: Gas Sampling Instrumentation Set Up

4.2 Laboratory Demonstration Test Results

Exhaust emissions from the Capstone C65 microturbine were monitored throughout testing to provide a baseline for comparison with the FlexCHP system. Typical emissions from the microturbine are reported in Table 6, with Nitrogen Oxide(s) (NOx), Carbon Monoxide (CO), and Total Hydrocarbons (THC) corrected to 15 percent oxygen content. The turbine exhaust temperature was measured and typically found to be 615 °F.

Table 6: Typical Microturbine Emissions and Optimal FlexCHP Emissions

Constituent	Microturbine (typical)	FlexCHP System (optimal)
NOx [vppm]	4.5	2.5
CO [vppm]	31	0.6
THC [vppm]	20[3]	0.5 (measurement resolution)
Oxygen [%]	17.8	9.0

When the supplemental ULN burner is operated under optimal firing conditions, the emissions are greatly reduced in comparison with the turbine exhaust. As shown in Table 6, NOx emissions are reduced from 4.5 to 2.5 vppm; a reduction of over 44 percent. The decreases in CO and THC emissions are even more significant, with emissions levels dropping to near zero for the FlexCHP system. This decrease indicates that the FlexCHP system achieves high overall combustion efficiency in comparison to the microturbine alone.

The original ULN supplemental burner configuration evaluated during the laboratory demonstration did not initially allow for the FlexCHP system to achieve CARB 2007 emissions criteria for NOx over the full range of firing rates. To meet this objective, several contingency variables were evaluated to refine the burner performance including nozzle designs, fuel/air mixing designs, and sleeve designs. Figure 20 shows a typical flame image for the supplemental burner. The NOx emissions for the initial and final burner configurations are shown in Figure 21 for the full range of supplemental burner firing rates. As a result of optimizing the burner design, NOx emissions were reduced by as much as 40 percent between the initial and final burner configurations.

[3] Measured at the FlexCHP system exhaust stack while the supplemental ULN burner was not in operation

Figure 20: Typical Flame Image for the Supplemental ULN Burner

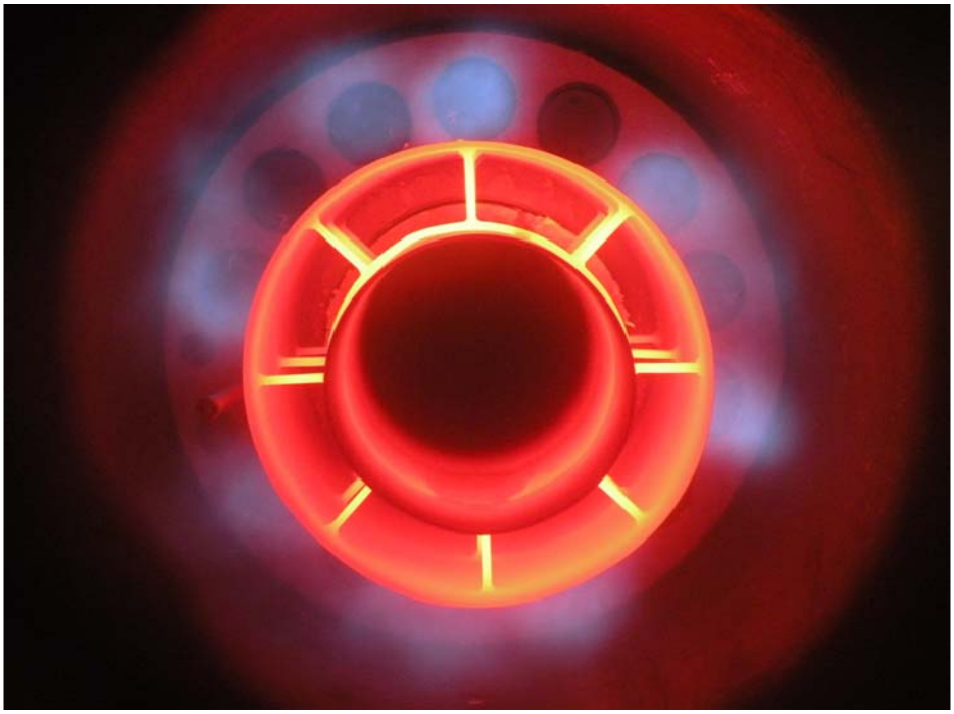
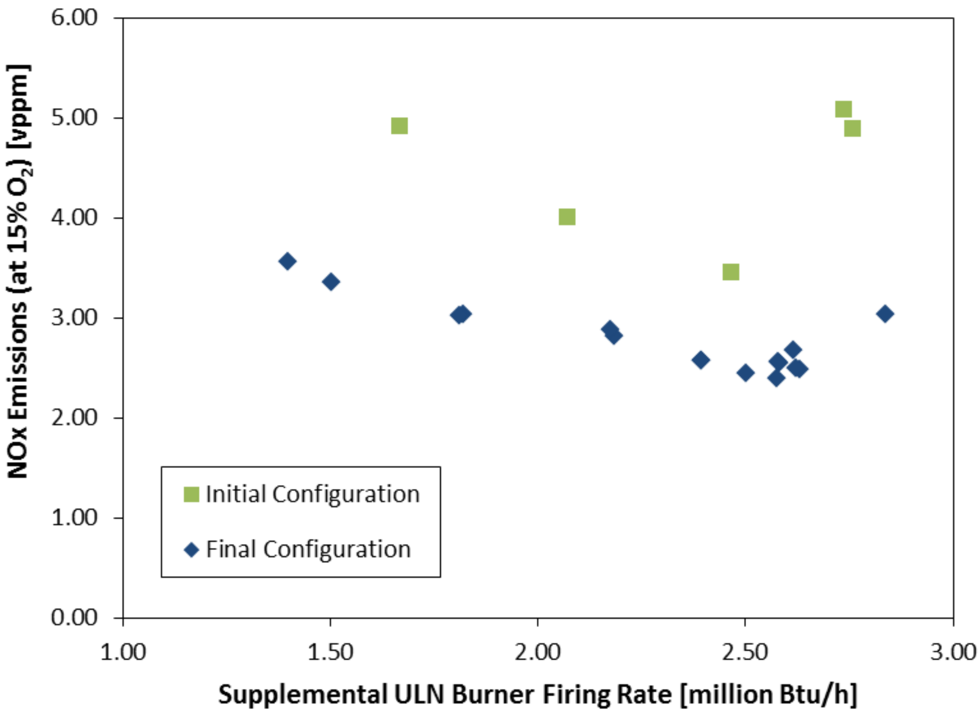


Figure 21: FlexCHP NOx Emissions for Initial and Final ULN Burner Configurations



Carbon monoxide emissions were also decreased substantially as a result of alterations to the burner design as shown in Figure 24. The CO emissions decrease as the supplemental ULN burner firing rate is increased, approaching values near zero at the maximum firing rate.

Total hydrocarbon emissions were not measured during evaluation of the original burner configuration. Measurements of the THC emissions for the final burner configuration showed that the emissions were zero within the measurement resolution (0.5 vppm) for all firing rates evaluated.

In addition to firing rate, an additional key operating parameter which impacts burner emissions is that of the combustion zone oxygen content. This parameter could be varied by adjusting the amount of turbine exhaust gas which is allowed to flow through the primary burner nozzles. The impact of combustion zone oxygen content on NOx and CO emissions for the final burner configuration can be seen in Figure 23 for a firing rate of 2.2 million Btu/h. Although the CO emissions were not greatly affected by the combustion zone oxygen content, the NOx emissions decreased 33 percent from 4.2 to 2.8 vppm as the oxygen content was increased. This reduction is a result of reduced flame temperatures with higher oxygen content in the combustion zone.

Figure 22: FlexCHP CO Emissions for Initial and Final ULN Burner Configurations

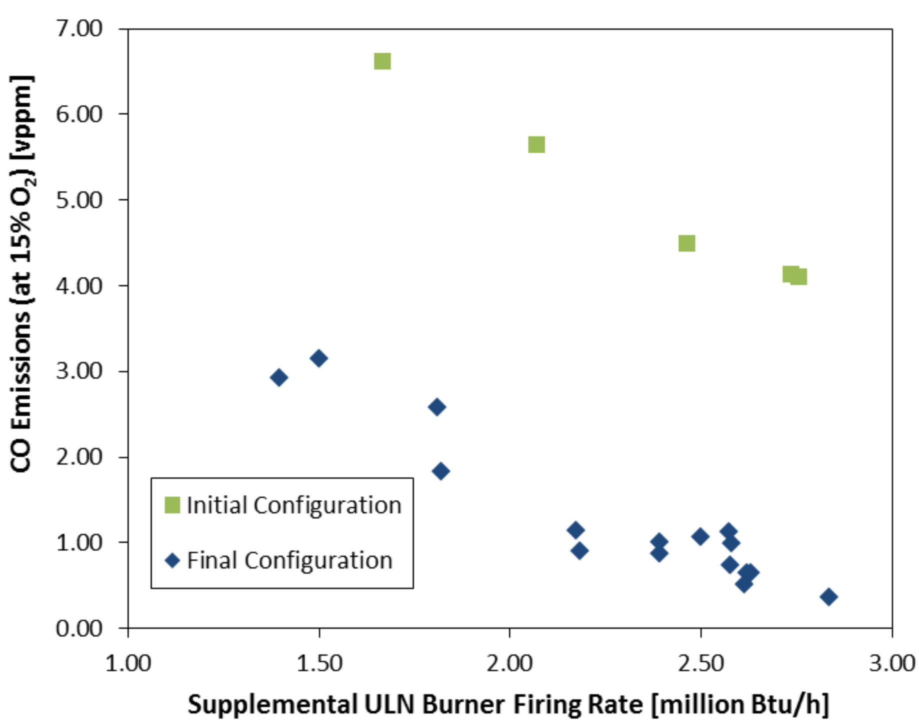
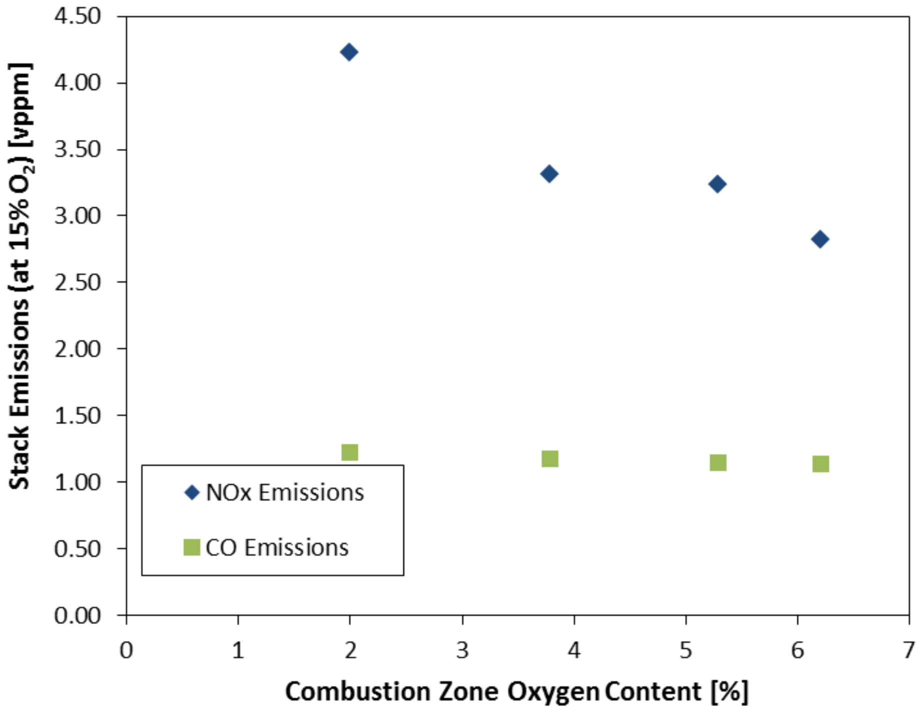


Figure 23: FlexCHP Emissions as a Function of Combustion Zone Oxygen Content



A primary objective of this project was to ensure that the FlexCHP system is capable of achieving CARB 2007 emissions criteria. This requires the system to emit less than 0.07, 0.10, and 0.02 lb/MW-h of NOx, CO, and THC respectively. To assess the performance of the FlexCHP system relative to these standards, the emissions results have been converted to a pounds per megawatt-hour basis by assuming a final stack temperature of 300 °F and an 80 percent fuel efficiency of the supplemental burner fuel input as based on the higher heating value. As such, the NOx and CO emissions shown in Figure 24 and Figure 25 represent estimates of the system performance in terms of energy output. The actual performance of the system relative to the CARB 2007 emissions criteria was determined during the field evaluation phase, in which all required measurements for energy inputs and outputs were available.

For both NOx and CO emissions, the FlexCHP system satisfies CARB 2007 criteria over the full range of firing rates. Regarding carbon monoxide, the burner performance continues to improve with increasing firing rate, with emissions far below the required CARB 2007 emissions standards. For NOx emissions, levels decrease with increasing firing rate until reaching a point at which there is insufficient turbine exhaust gas (i.e. flame oxidizer) available to deliver to the primary combustion zone to keep flame temperatures cool enough to suppress thermal NOx formation.

Figure 24: FlexCHP Performance Relative to CARB 2007 Emissions Standards for NOx

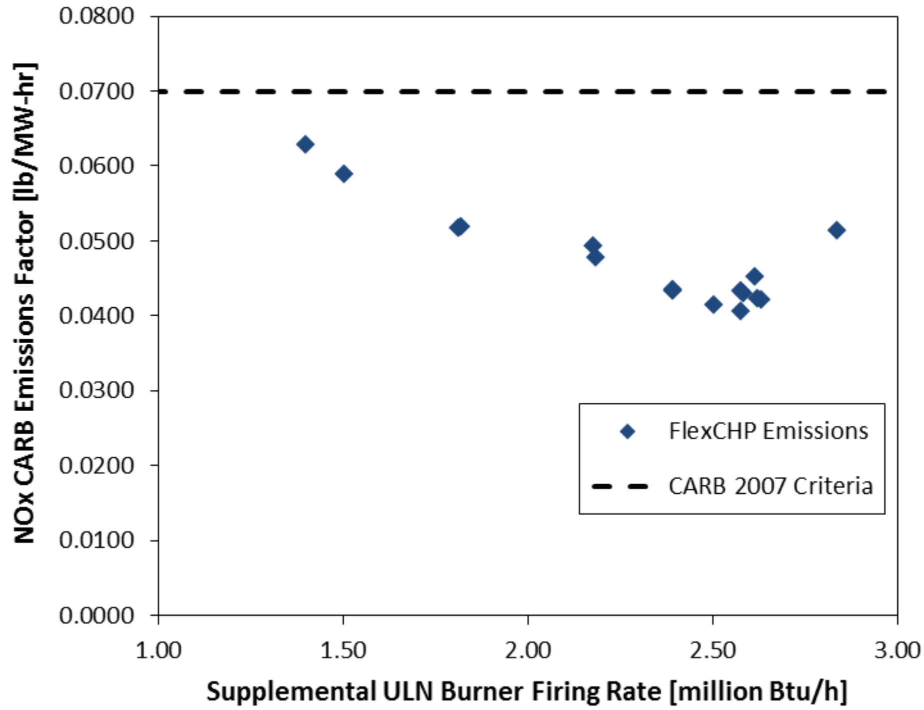
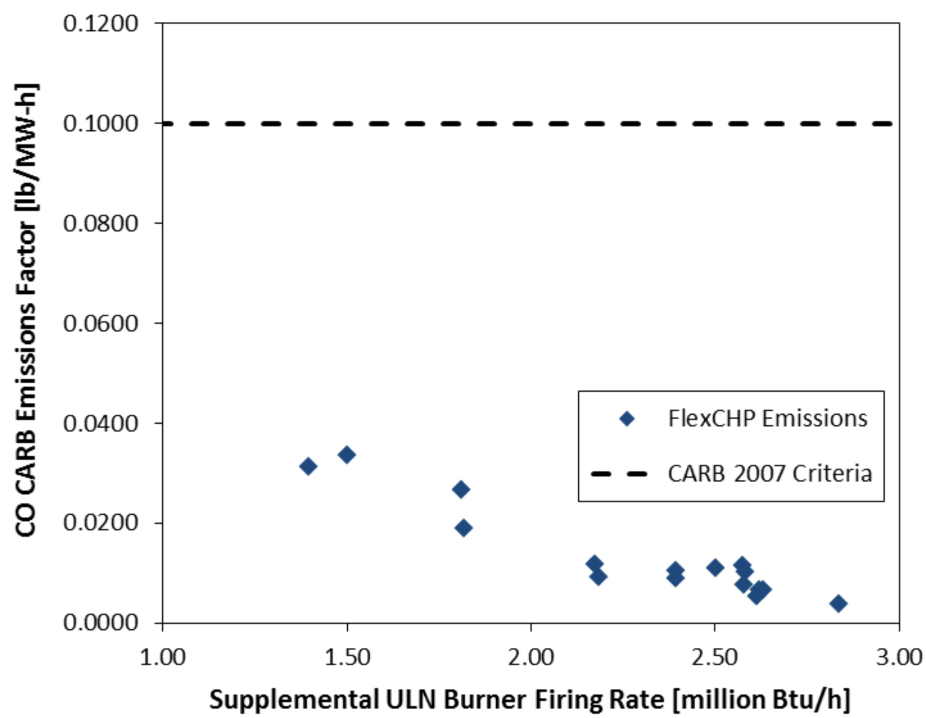


Figure 25: FlexCHP Performance Relative to CARB 2007 Emissions Standards for CO



Total hydrocarbon emissions were zero to within the resolution of the measurement device (0.5 vppm) for the full range of firing rates evaluated. This corresponds to a CARB emissions factor of less than 0.0015 lb/MW-h, which is far less than the required 0.02 lb/MW-h emissions level.

In addition to satisfying CARB 2007 emissions standards and achieving an overall system efficiency of 84 percent, this project seeks to produce a distributed generation system which is capable of matching thermal and electric loads to meet varying user demands.

The turndown ratio could be increased somewhat while maintaining compliance with CARB emissions criteria if the supplemental burner firing rate were increased beyond the current maximum value of 2.8 million Btu/h reported here. To achieve these higher firing rates, the natural gas delivery pressure would need to be increased beyond the current delivery pressure of 10 psi employed. This pressure limitation was maintained during the laboratory testing phase to match the current 10 psi natural gas delivery pressure available at the field demonstration site for this project.

The turndown ratio might also be increased by allowing the microturbine to operate under lower loads. For all studies performed during the laboratory testing phase however, the microturbine was operated at full fire to maintain satisfactory turbine exhaust emissions and increase turbine operating lifetime. It is possible that allowing the turbine to operate at lower power outputs might allow for stable supplemental burner combustion at lower firing rates, thereby increasing overall turndown ratio. Nonetheless, the current turndown ratio is adequate for user demands at the project field demonstration site.

The laboratory demonstration has shown the FlexCHP system to be capable of meeting CARB 2007 emissions criteria over full turndown in supplemental burner firing rate. Thorough testing and evaluation of varying burner configurations throughout the laboratory demonstration phase have resulted in a final supplemental ULN burner design which achieves the desired performance objectives of this project.

4.3 Field Demonstration Test Methods

The field demonstration test methods employed are aimed at quantifying overall system efficiency and performance relative to CARB 2007 emissions standards for distributed generation systems. As this work has focused primarily on development of the ULN burner, the key measure of success for this project lies in demonstrating that the FlexCHP system can achieve pollutant emission levels of Nitrogen Oxides (NOx), Carbon Monoxide (CO), and Total Hydrocarbons (THC) below 0.07, 0.10, and 0.02 lb/MW-h respectively. Additional measures of the FlexCHP system performance to be evaluated include achieving an overall system efficiency of 84 percent and meeting facility electrical and steam demands.

In the areas where applicable, the Association of State Energy Research and Technology Transfer Institutions (ASERTTI) Performance Testing and Reporting Protocols are used as a basis for the testing described here. The ASERTTI Protocols are intended to provide data on the electrical, thermal, emissions, and operational performance of commercial distributed generation systems. Application of the protocol provides uniform data of known quality that is obtained in a consistent manner for all systems evaluated. The common areas considered are definitions of system boundaries, testing procedures, and instrumentation guidelines.

The thermodynamic system boundary evaluated during field testing is shown in Figure 26 along with the relevant energy flows considered. Energy inputs to the system include electricity to the microturbine (compressors, controls) and boiler system (feed water pumps, controls), natural gas inputs to the microturbine and ULN burner, and hot water inputs to the economizer and boiler. Useful energy outputs from the system include electricity generated by the microturbine, hot water from the economizer, and steam generated by the boiler. Energy losses from the system include thermal energy stored in the exhaust gases and convection and radiation from the system to the surroundings. These energy flows are described in further detail in Table 7.

Figure 26: Thermodynamic Boundary and Corresponding Energy Flows for Field Evaluation of FlexCHP System

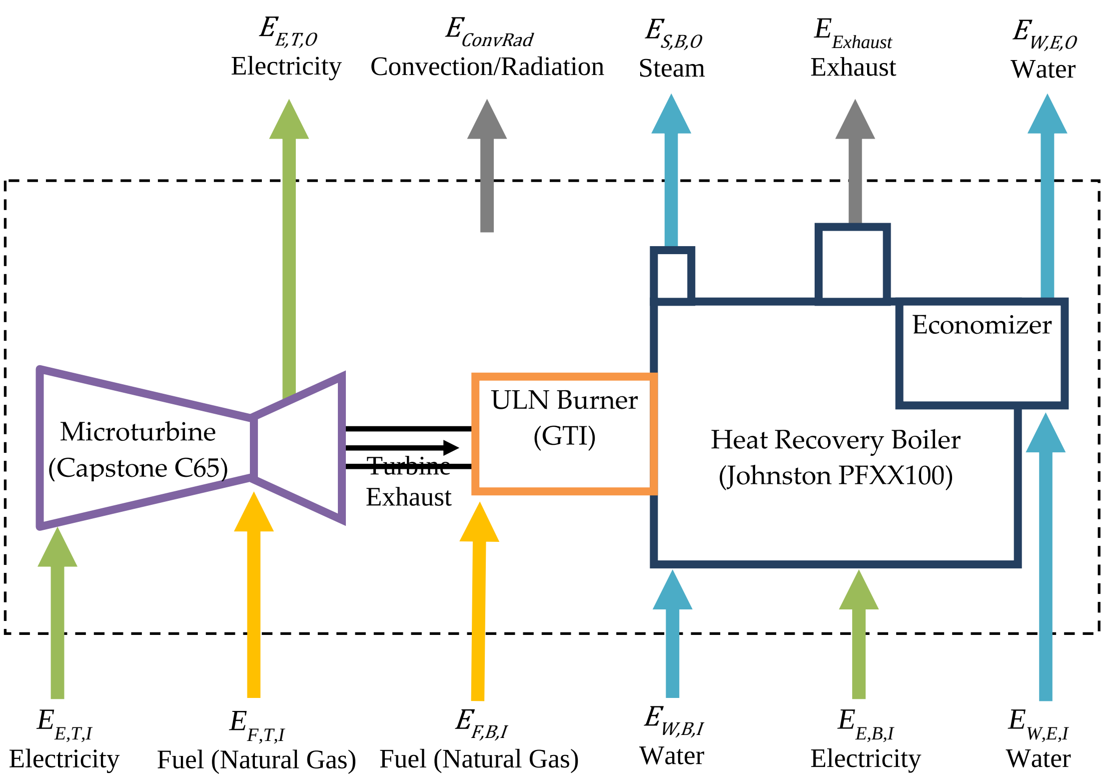


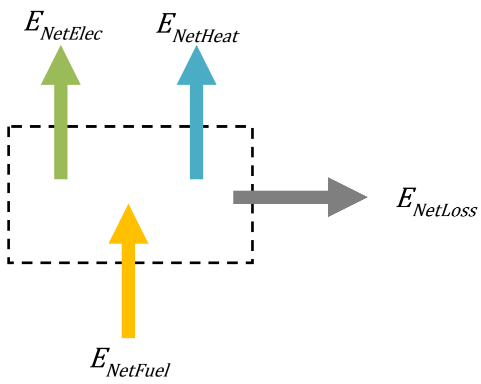
Table 7: Description of Energy Flows for FlexCHP System

Label	Description	Type
$E_{E,T,O}$	Electrical output from microturbine to facility	Output
$E_{ConvRad}$	Convection and radiation heat transfer from system to surroundings	Loss
$E_{S,B,O}$	Steam output from the boiler to facility	Output
$E_{Exhaust}$	Exhaust from the boiler to atmosphere (stack losses)	Loss
$E_{W,E,O}$	Water output from the economizer to the boiler feed water tank	Output
$E_{E,T,I}$	Electricity input to the microturbine from facility supply (compressor, controls)	Input
$E_{F,T,I}$	Fuel (natural gas) input to the turbine from facility supply	Input
$E_{F,B,I}$	Fuel (natural gas) input to the ULN burner from facility supply	Input
$E_{W,B,I}$	Water input to the boiler from boiler feed water tank	Input
$E_{E,B,I}$	Electricity to the boiler from the facility supply (feed water pumps, controls)	Input
$E_{W,E,I}$	Water input to the economizer from boiler feed water tank	Input

The system boundary has been drawn in such a way to isolate the FlexCHP system from the broader facility as much as possible so that the performance of the FlexCHP system may be accurately assessed in and of itself. Since the FlexCHP system is intended to be an adaptable technology which can be deployed in a wide range of facility types, it is of interest to characterize the system performance independently of the facility. To this end, the boiler feedwater tank at the demonstration facility has not been included in the system boundary, as this tank serves multiple boilers and is therefore difficult to thermally isolate from other energy inputs.

To analyze the system performance in terms of CARB 2007 emissions criteria and system efficiency, net energy flows are considered relative to the system boundary as shown in Figure 26. The relevant net energy inputs and outputs include the net electrical output ($E_{NetElec}$), the net heat recovered ($E_{NetHeat}$), the net fuel input to the system ($E_{NetFuel}$), and the net energy loss from the system ($E_{NetLoss}$). These net energy flows are defined by Equations *(1)*, *(2)*, *(3)*, and *(4)* in terms of the energy inputs and outputs described in Table 7.

Figure 27: Net Energy Flows Relative to System Boundary



$$E_{NetElec} = E_{E,T,O} - E_{E,T,I} - E_{E,B,I} \tag{1}$$

$$E_{NetHeat} = \left(E_{S,B,O} - E_{W,B,I}\right) + \left(E_{W,E,O} - E_{W,E,I}\right) \tag{2}$$

$$E_{NetFuel} = E_{F,T,I} + E_{F,B,I} \tag{3}$$

$$E_{NetLoss} = E_{ConvRad} + E_{Exhaust} \tag{4}$$

The CARB 2007 standard is an output based emissions criteria which incorporates energy credits for both electrical and thermal net output. For the FlexCHP system the total useful energy output includes both the net electricity generated ($E_{NetElec}$) and the net heat recovered ($E_{NetHeat}$). The overall system efficiency is also considered in terms of both thermal and electric net outputs, with the net fuel energy ($E_{NetFuel}$) considered as the net energy input to the system.

The CARB 2007 standard is an output based criteria which defines emission levels ($CARB_{Pol}$) in terms of mass flow rate of pollutant ($\dot{m}_{Pol}$) per unit of useful energy output in accordance with Equation *(5)*. The net power output ($E_{NetOutput}$) is the combined sum of net electrical output ($E_{NetElec}$) and net heat recovered ($E_{NetHeat}$). While the electrical and heat outputs are not equal in energy quality, they are both valued equally as useful energy outputs for CHP systems since there is a need for both electrical and heat at the installation site[4]. The pertinent pollutants to be evaluated are NOx, CO, and THC with corresponding target emission limits of 0.07, 0.10, and 0.02 lb/MW-h, respectively. Thus, Equation *(5)* applies to each of these pollutants, with the

[4] http://www.epa.gov/chp/basic/methods.html

subscript “Pol” being replaced by “NOx,” “CO,” or “THC,” depending on the pollutant being evaluated.

$$CARB_{Pol} = \frac{\dot{m}_{Pol}}{E_{NetElec} + E_{NetHeat}} \qquad (5)$$

To determine the net electricity generated by the system, Equation *(1)* are used along with measurements of the net electrical power output for the microturbine ($E_{E,T,Net}$) and an estimation of the total electrical input to the boiler ($E_{E,B,I}$). The magnitude of $E_{E,B,I}$ is small in comparison to $E_{E,T,Net}$, and as such, an estimation of this parameter based on the horsepower ratings for the boiler and economizer feed water pumps and power supply ratings for the control systems are adequate for quantifying this energy input. The measurement methods and corresponding instrumentation to be used for determining the net electricity ($E_{NetElec}$) generated are summarized in Table 8.

Table 8: Relevant Measurements for Determining the Net Electricity Generated ($E_{NetElec}$)

Variable	Measurement Method	Instrument
$E_{E,T,Net}$	Power meter	Veris Industries H8042-0100-2
$E_{E,B,I}$	Value estimated from feed water pump horsepower ratings and control panel power supply ratings	Not Applicable

To determine the net heat recovered by the FlexCHP system ($E_{NetHeat}$), the energy increase of the water delivered to the economizer and boiler are quantified. Rather than directly measuring the water energy flows labeled in Figure 26, the $E_{NetHeat}$ are determined by measuring the sensible temperature rise of the water as it passes through the economizer ($E_{HeatEconSens}$), the sensible temperature rise of the water as it is raised from the feedwater temperature to the boiling point ($E_{HeatBoilSens}$), and the latent heat of the water as its vaporizes to steam at the boiler exit ($E_{HeatBoilLatent}$) and summing them up according to Equation *(6)*. Note that this approach is thermodynamically equivalent to the net heat recovery definition given in Equation *(2)*.

$$E_{NetHeat} = E_{HeatEconSens} + E_{HeatBoilSens} + E_{HeatBoilLatent} \qquad (6)$$

The sensible heat recovered by the economizer ($E_{HeatEconSens}$) is determined according to Equation *(7)* by measuring the volumetric flow rate of liquid water to economizer ($Q_{W,E}$) and the temperature of the water at the outlet and inlet of the economizer ($T_{W,E,O}$ and $T_{W,E,I}$). The density ($\rho_{W,E}$) and specific heat capacity at constant pressure ($Cp_{W,E}$) are determined from steam tables for the nominal conditions at the economizer.

$$E_{HeatEconSens} = \rho_{W,E}\, Q_{W,E}\, Cp_{W,E}\left(T_{W,E,O} - T_{W,E,I}\right) \tag{7}$$

The sensible heat recovered by the boiler ($E_{HeatBoilSens}$) in raising the boiler feed water to the saturation point are determined according to Equation *(8)* by measuring the volumetric flow rate of liquid water to the boiler ($Q_{W,B}$) and the temperature of the water at the inlet of the boiler ($T_{W,B,I}$). The saturation temperature ($T_{W,B,Sat}$) are determined from a steam table as based upon the measured boiler operating pressure (P_{Boil}). The values for the density ($\rho_{W,B}$) and specific heat capacity at constant pressure ($Cp_{W,B}$) are determined from steam tables for the nominal conditions at the boiler.

$$E_{HeatBoilSens} = \rho_{W,B}\, Q_{W,B}\, Cp_{W,B}\left(T_{W,B,Sat} - T_{W,B,I}\right) \tag{8}$$

The latent heat of the water as it vaporizes within the boiler ($E_{HeatBoilLatent}$) are determined according to Equation *(9)* by measuring the volumetric flow rate of liquid water to the boiler ($Q_{W,B}$). The values for the density ($\rho_{W,B}$) and heat of vaporization (ΔH_{Vap}) are determined from steam tables for the nominal conditions at the boiler.

$$E_{HeatBoilLatent} = \rho_{W,B}\, Q_{W,B}\, \Delta H_{Vap} \tag{9}$$

The measurement methods and corresponding instrumentation used for determining the net heat recovered ($E_{NetHeat}$) are summarized in Table 9. All temperature measurements are made as close to the thermodynamic boundary as possible to ensure that the results attained are representative of the performance of the FlexCHP system alone.

Table 9: Relevant Measurements for Determining the Net Heat Recovered ($E_{NetHeat}$)

Variable	Measurement Method	Instrument
$Q_{W,E}$	Orifice plate flow meter	Rosemount 1151DP7E22B1
$Q_{W,B}$	Orifice plate flow meter	Rosemount 1151DP7E22B1
$T_{W,E,I}$	T Type Thermocouple	Pyromation T48G-010-SL
$T_{W,E,O}$	T Type Thermocouple	Pyromation T48G-010-SL
$T_{W,B,I}$	T Type Thermocouple	Pyromation T48G-010-SL
P_{Boil}	Pressure transducer	Rosemount 1151DP7E22B1

In addition to determining the net energy output ($E_{NetOutput}$), the mass flow rate of the pollutant ($\dot{m}_{Pol}$) must be quantified in order to calculated the CARB criteria emissions level ($CARB_{Pol}$) defined in Equation *(5)*. The mass flow rate of pollutant emitted from the stack is determined according to Equation *(10)* by measuring the pollutant dry volume fraction concentration in the exhaust ($c_{Pol,dry}$) and the total standard volumetric flow rate of dry exhaust products ($Q_{Exhaust,dry,std}$). The standard density values for the pollutants ($\rho_{Pol,std}$) are based upon ideal gas relationships with molecular weights of 46, 28, and 14.33 kg/kmol for NOx, CO, and THC, respectively. This method for determining standard pollutant densities is in agreement the approach used by the distributed generator certification tool developed by CARB[5].

$$\dot{m}_{Pol} = \rho_{Pol,std}\, c_{Pol,dry}\, Q_{Exhaust,dry,std} \qquad (10)$$

The dry exhaust gas composition and pollutant concentrations ($c_{Pol,dry}$) are measured at the stack of the FlexCHP system. Gas samples are drawn through Teflon sample line by an oil-less vacuum pump at an approximate flowrate of 0.5 L/min. The samples are be sent through a sample drying train to remove all water content and ensure that concentration measurements are made on a dry basis. The sample gas stream is sent to emissions analyzers to measure concentration levels of Oxygen ($c_{O2,dry}$), Carbon Dioxide ($c_{CO2,dry}$), Oxides of Nitrogen ($c_{NOx,dry}$), Carbon Monoxide ($c_{CO,dry}$), and Total Hydrocarbons ($c_{THC,dry}$) on a dry volume basis.

[5] http://www.arb.ca.gov/energy/dg/certification_calculation_tool.xls

The measurement method and corresponding instruments to be used for determining exhaust concentrations are given in Table 10. The gas analyzers are calibrated immediately before and after recording data sets, to assess drift and ensure the instrument is still within calibration range. All calibration gases used are certified to an accuracy of ±2 percent traceable to NIST.

Table 10: Relevant Measurements for Determining the Mass Flow Rate of Pollutants ($\dot{m}_{Pol}$)

Variable	Measurement Method	Instrument
$c_{O2,dry}$	Zirconia sensor	Horiba PG-250A
$c_{CO2,dry}$	Nondispersive Infrared	Horiba PG-250A
$c_{NOx,dry}$	Chemiluminescence	Horiba PG-250A
$c_{CO,dry}$	Nondispersive Infrared	Horiba PG-250A
$c_{THC,dry}$	Flame Ionization	Rosemount 400A
$Q_{F,T,std}$	Turbine Flowmeter	Blancett B5142-20L
$Q_{F,B,std}$	Turbine Flowmeter	Blancett B142-20L

The total standard volumetric flow rate of dry exhaust products ($Q_{Exhaust,dry,std}$) is calculated by determining the overall combustion air-fuel ratio (AFR) and total natural gas flow rate to the FlexCHP system. The overall AFR is calculated from the measured concentration of oxygen in the exhaust ($c_{O2,dry}$) and the composition of the natural gas delivered to the system. The fuel property data for the natural gas used at the field demonstration facility is attained from the local gas distribution company, Southern California Gas Company, to aid in this calculation. Combining the AFR with the total standard volumetric flow rate of natural gas delivered to the microturbine ($Q_{F,T,std}$) and ULN burner ($Q_{F,B,std}$) allows for a determination of the overall dry standard volumetric flow rate of exhaust products ($Q_{Exhaust,dry,std}$).

The overall system efficiency (η_{System}) is defined as a ratio of the total energy output, including net electrical output ($E_{NetElec}$) and the net heat recovered ($E_{NetHeat}$), to the net fuel energy input ($E_{NetFuel}$) according to Equation *(11)*. This method for determining overall system efficiency is in agreement with the definition for system efficiency of CHP systems put forth by the Environmental Protection Agency[6].

[6] http://www.epa.gov/chp/basic/methods.html

$$\eta_{System} = \frac{E_{NetElec} + E_{NetHeat}}{E_{NetFuel}} \tag{11}$$

The methodologies for determining the net electrical output ($E_{NetElec}$) and the net heat recovered ($E_{NetHeat}$) are discussed above and the relevant measurements outlined in Table 7 and Table 8. The net fuel energy input to the system is based on the higher heating value of the fuel (HHV_F) and the standard volumetric flow rates of natural gas to the microturbine ($Q_{F,T,std}$) and ULN burner ($Q_{F,B,std}$) as described by Equation *(12)*. The measurement methodologies for the natural gas flow rates are outlined in Table 9. The (HHV_F) is acquired from the local gas distribution company, Southern California Gas Company, as based upon an analysis of the natural gas delivered to the field demonstration site.

$$E_{NetFuel} = HHV_F \left(Q_{F,T,std} + Q_{F,B,std}\right) \tag{12}$$

The performance of the FlexCHP system was evaluated at the field demonstration site, Inland Empire Foods, in Riverside, California. Data was collected immediately after installation. All data points described above in Table 7, Table 8, and Table 9 are measured during each set of tests to determine the system performance in terms of CARB 2007 emissions criteria and overall system efficiency.

The FlexCHP system was designed to operate with the microturbine at full fire whenever the system is on line. This ensures high efficiency operation of the microturbine and provides a steady stream of turbine exhaust for delivery to the supplemental ULN burner. To meet steam load demands, the firing rate of the supplemental burner can be varied. The performance of the FlexCHP was evaluated over its full operating range by collecting data at 60, 75, and 100 percent of supplemental ULN burner full firing rate. After adjusting the burner firing rate, the system was operated for 30 minutes to allow for the system to reach steady state. Data was then collected over a 30 minute period to provide an adequate sample for evaluating system performance. This procedure is outlined as follows.

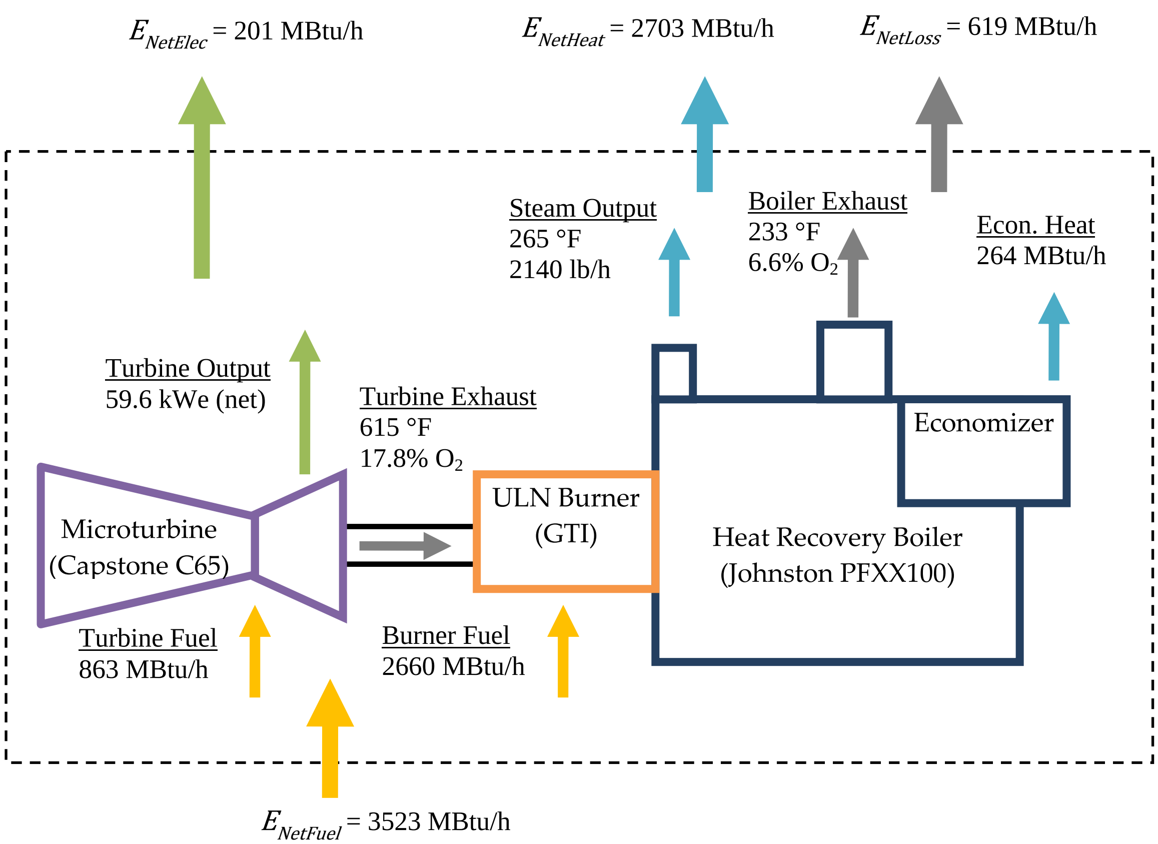
1) Set system to 60 percent firing rate and hold for 30 minutes to allow system to reach steady state.
2) Collect data at 60 percent firing rate for 30 minute period.
3) Set system to 75 percent firing rate and hold for 30 minutes to allow system to reach steady state.
4) Collect data at 75 percent firing rate for 30 minute period.
5) Set system to 100 percent firing rate and hold for 30 minutes to allow system to reach steady state.

6) Collect data at 100 percent firing rate for 30 minute period.

4.4 Field Demonstration Test Results

An overview of the FlexCHP performance and associated energy flows is shown in Figure 28. The electricity demands at the Inland Empire Foods facility are high enough that the microturbine operates at full capacity at all times when production is running. At full load, the microturbine draws 863 MBtu/h of natural gas and delivers a net power output of 59.6 kWe, giving a turbine efficiency of 23.6 percent on a HHV basis.

Figure 28: Overview of FlexCHP Energy Flows for Operation at Full Load Capacity



The steam demands of the facility vary according to process needs, and the FlexCHP meets these requirements by varying the firing rate of the supplemental ULN burner. At full fire conditions; 2,660 MBtu/h of natural gas are delivered to the ULN burner providing a steam production rate of 2,140 lb/h.

The FlexCHP system, as shown in Figure 29, provides an increase to overall efficiency as compared to the microturbine operating alone by recovering the heat available in the exhaust of the turbine. The exhaust gases leaving the turbine at 615 °F are reduced in temperature and exit the boiler at 233 °F. Further, the oxygen content is reduced from 17.8 percent at the turbine exit to 6.6 percent in the boiler stack, leading to an even greater enhancement of system efficiency. By recovering this sensible heat in the form of steam, value is added to the waste heat from the microturbine exhaust and a significant increase in system efficiency is achieved. At full fire conditions the overall efficiency, on a HHV basis, for the FlexCHP system is 82.4 percent (based on measured steam and power outputs and natural gas input) or 84.2 percent (based on estimated flue gas and boiler jacket losses), which is substantially higher than the 23.6 percent efficiency measured for the turbine alone.

Figure 29: FlexCHP Installation at Inland Empire Foods

In addition to offering an improvement to system efficiency, the FlexCHP combined heat and power package provides a significant reduction in pollutant emission as compared to the turbine operating alone. For all three criteria pollutants evaluated; NOx, CO, and THC, the FlexCHP package delivers significant reductions in emissions levels across the ULN firing range as shown in

Figure 30, Figure 31, and Figure 32. Under optimal conditions, the NOx emissions are reduced 48 percent from 4.0 vppm to 2.1 vppm. Similarly, the CO emissions are reduced by 97 percent at full load conditions for the supplemental ULN burner.

Figure 30: FlexCHP NOx Emissions Relative to Microturbine Emissions

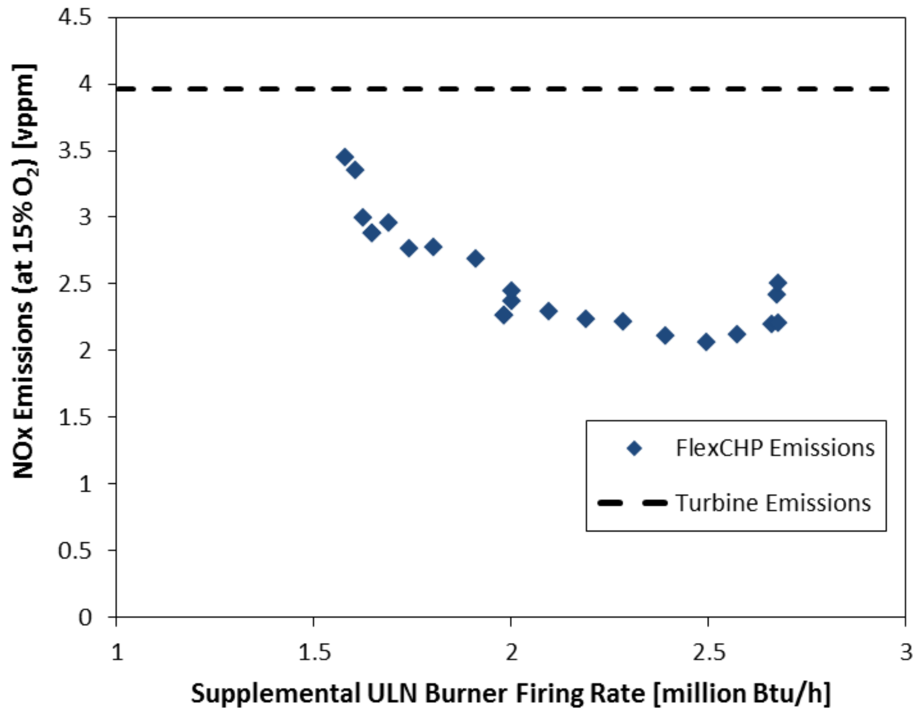
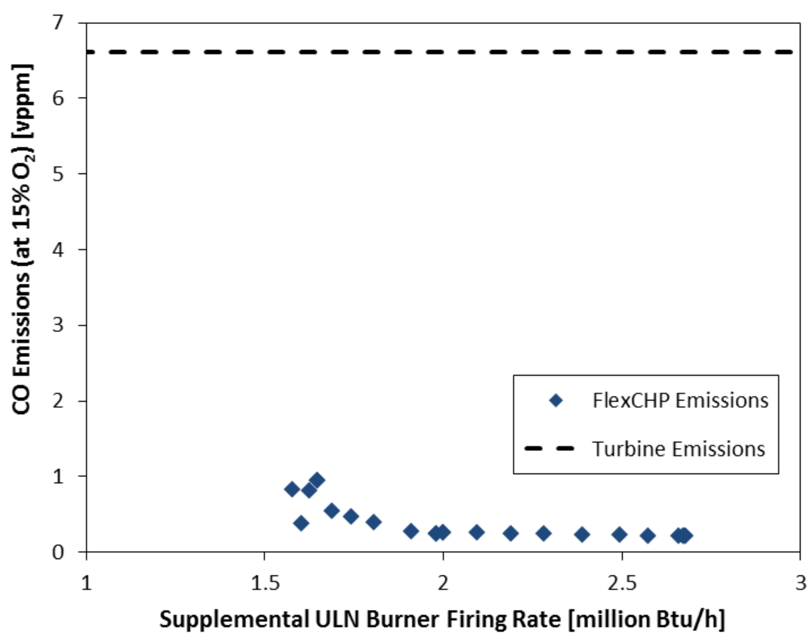
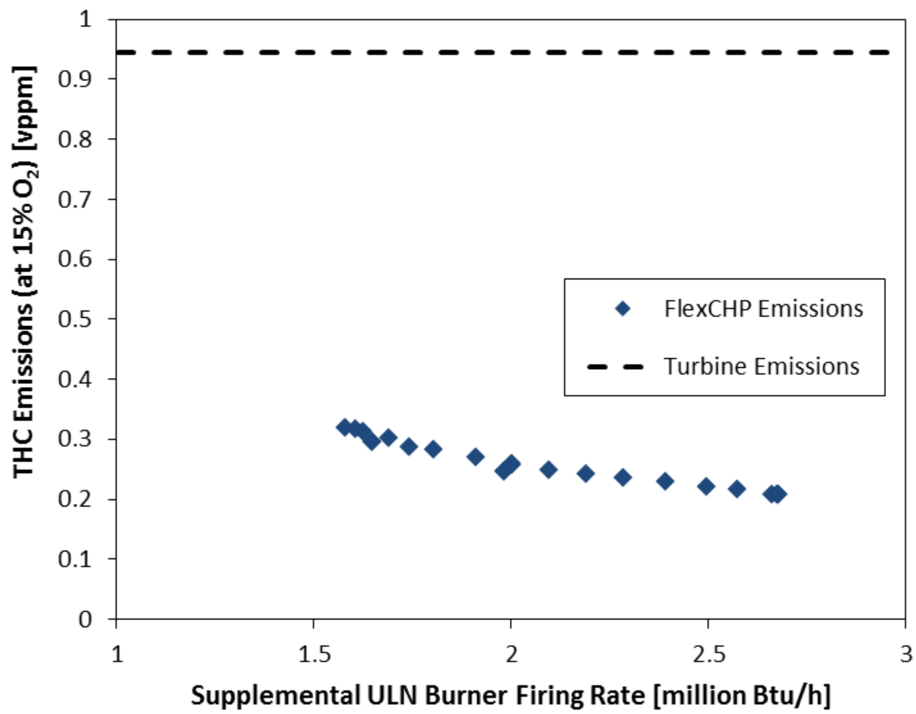


Figure 31: FlexCHP CO Emissions Relative to Microturbine Emissions



Total unburned hydrocarbon emissions for both the FlexCHP system and microturbine were measured to be zero within the instrument resolution (0.5 vppm) for all conditions evaluated. The data shown in Figure 32 represent a THC emission level of 0.5 vppm corrected for the oxygen content at the measured condition. The data has been shown this way, rather than presenting a value of zero as measured, to demonstrate the impact of this measurement uncertainty on the emissions results in terms of stack oxygen content.

Figure 32: FlexCHP THC Emissions Relative to Microturbine Emissions



As was found during the laboratory demonstration tests, the CO emissions continue to decrease with increasing supplemental burner firing rate. Similarly, the trends for NOx emissions agree with those observed during the laboratory demonstration, decreasing with firing rate to approximately 2.5 million Btu/h and then increasing. For both the laboratory and field demonstrations, THC emissions have remained near zero for all conditions.

The microturbine emissions measured during the field performance evaluation were improved over those measured during the laboratory demonstration performance. This is thought to be a result of the commissioning of the microturbine by the local Capstone dealer after the turbine was delivered to the host site.

Regarding performance relative to the CARB 2007 criteria, the emissions values have been converted to a lb/MW-h basis via the methodology laid out in “The Field Performance Testing and Reporting Plan.” Because the THC values were measured to be zero, the resolution of the gas analyzer (0.5 vppm) has been used instead to demonstrate the effect of supplemental burner firing rate (i.e. stack oxygen content).

The performance of the FlexCHP relative to the CARB 2007 emission criteria are shown in Figure 33, Figure 34, and Figure 35, for NOx, CO, and THC respectively. For all three pollutants, the FlexCHP emissions are well below the CARB 2007 requirements for the full range of supplemental burner firing rates. These results demonstrate that the FlexCHP combined heat and power package has the ability to far exceed some of the most stringent regulatory standards for distributed generation systems. In particular, regarding NOx emissions, levels are measured to be 50 percent below the requirement of 0.07 lb/MW-h.

Figure 33: FlexCHP Field Performance Relative to CARB 2007 Emissions Standards for NOx

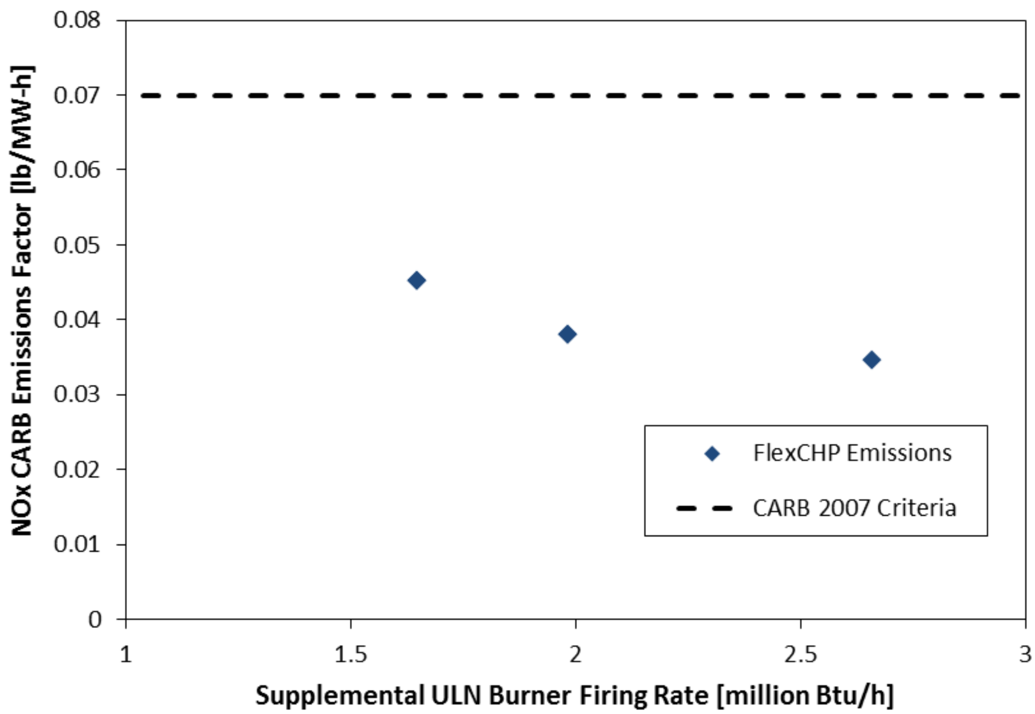


Figure 34: FlexCHP Field Performance Relative to CARB 2007 Emissions Standards for CO

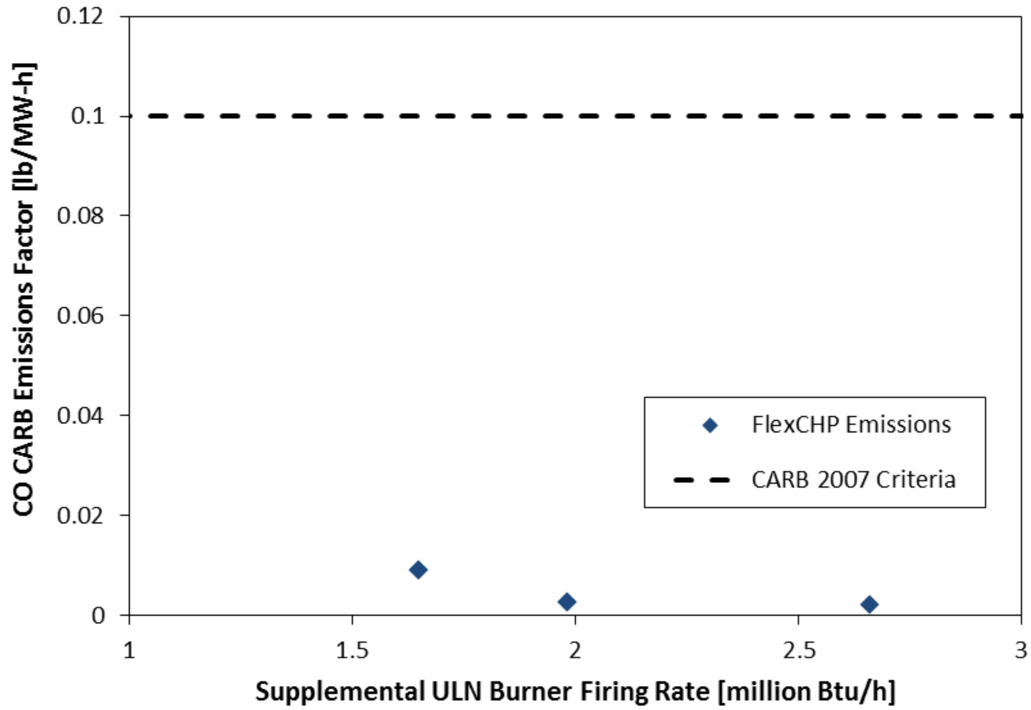
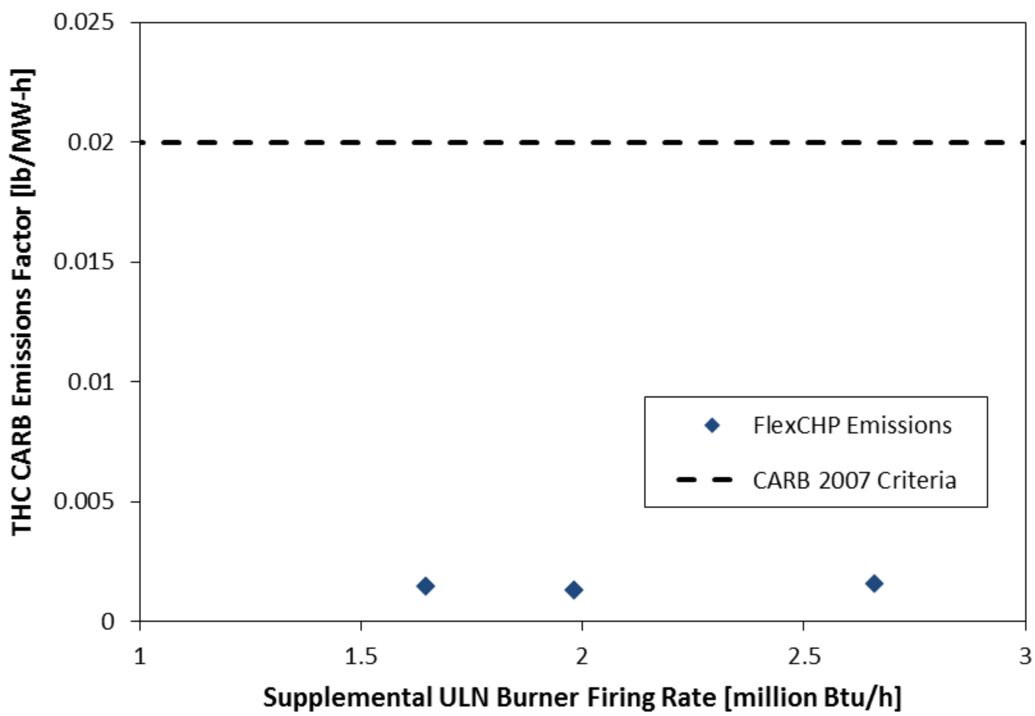


Figure 35: FlexCHP Field Performance Relative to CARB 2007 Emissions Standards for THC



CHAPTER 5: Market Assessment

The objective of this study was to determine what opportunities exist for heating industrial thermal processes with a gas-fired supplemental or reheat burner, using the exhaust of microturbines as an oxygen source.

Microturbines are gaining acceptance for on-site generation of electrical power. They produce significant volumes of exhaust gases at temperatures of about 500-600°F. Those gases contain, on the average, 17-18 percent oxygen by volume, so they could be used as a source of combustion air for a burner system firing another process. The potential benefits from this turbine-process coupling include reduced gas and electrical consumption, lower installation costs and reduced air emissions, compared to the two systems operating separately.

The study identified seven generic classes of gas-fired applications with technical and operating characteristics that make them potential candidates for firing with turbine exhaust gas. Next, the potential energy efficiency and cost advantages of turbine exhaust systems were investigated. These studies led to the conclusion for processes operating at or below 1400°F exhaust temperature, there will be up to a 12 percent improvement in fuel efficiency by converting processes fired with conventional ambient combustion air to reheated turbine exhaust, in addition to some savings in electrical energy. From 1400 to 2400°F exhaust temperature, efficiencies of the two competing methods are essentially the same.

Equipment costs were studied in great detail, leading to the conclusion the turbine exhaust system will cost about the same as a conventional combustion system. The study identified the cost of the exhaust ductwork and control valves as a major factor, suggesting applications with the best potential for financial acceptance were single-burner units located close to the turbine.

Emissions levels will have the greatest impact on the salability of the system. If the supplemental or reheat burner is able to produce NOx in the 20 ppmv range, there will be an overall reduction in emissions compared to a turbine and fired process operating separately. If the NOx emissions of the burner can be taken down to the 15 ppmv range or lower, it will be able to compete with low or ultra-low NOx systems and command a higher selling price. Achieving this emissions level with existing gas turbines or those that are expected to enter the market is challenging. A supplemental burner using advanced design to reduce NOx from gas-fired TEG will be a real breakthrough in bringing cost-effective CHP solutions to the market. This will present an alternative solution and eliminate the need for costly SCR.

Of the seven application groups studied, the boiler market encompasses about eight times the number of units as the other six combined. Boilers are most likely of all the types to be located where microturbines can be placed close to them, and the exhaust connection between the turbine and the reheat burner can be made at the least expense. These are compelling reasons to focus on developing supplemental burners for boiler applications only. The resulting burners will probably also be suitable for use on absorption chillers and some types of process heaters.

5.1 Microturbine/Process Heating Power Options

Five microturbine/process heating options (see Figure 36 and

Figure 37) were initially studied. Three of those combinations were eliminated from consideration because they did not fit the objectives of this project. Options 2 and 4 were retained as the basis for further feasibility studies.

Figure 36: Microturbine Process Heating/Power Options 1-3

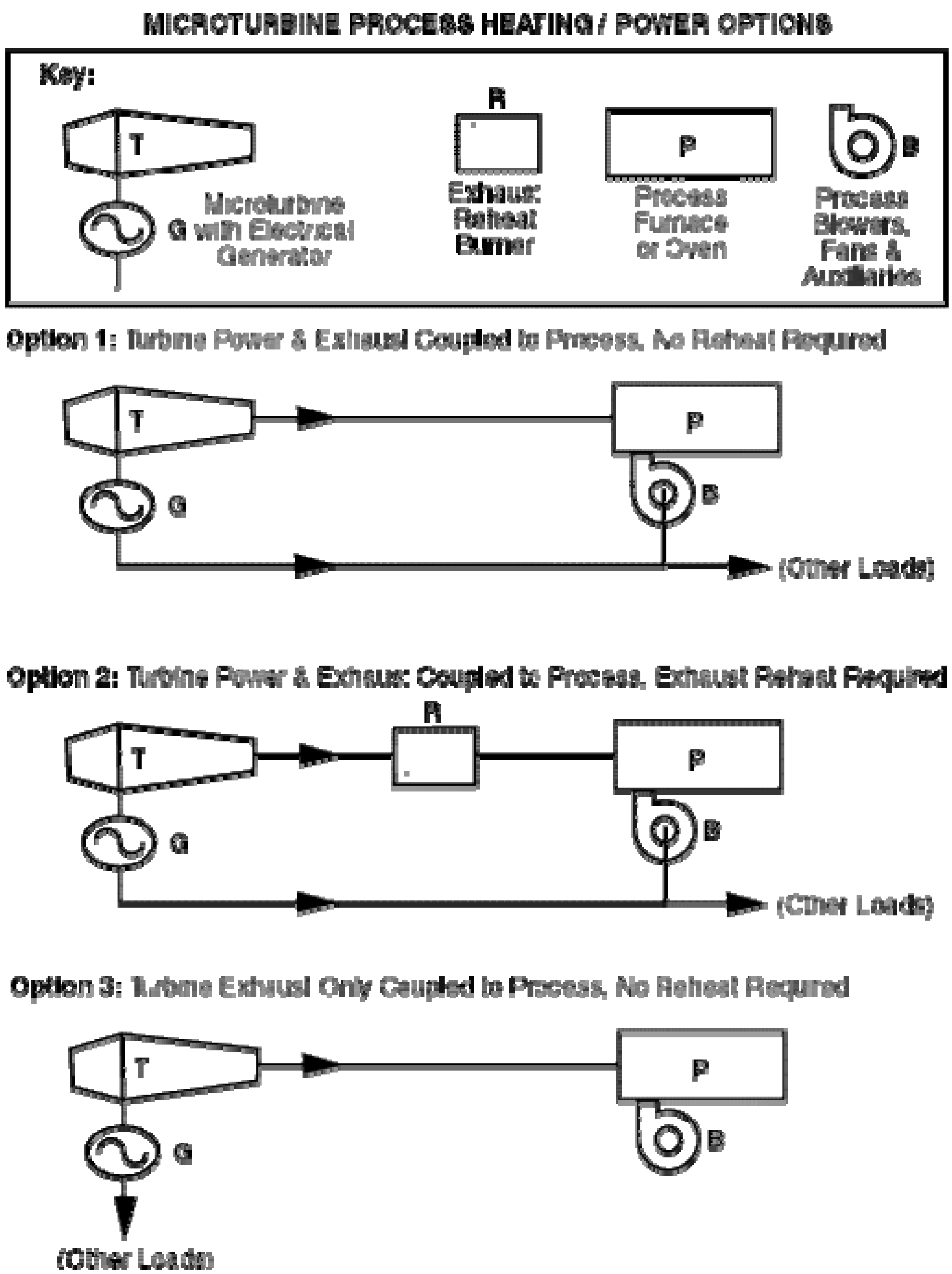
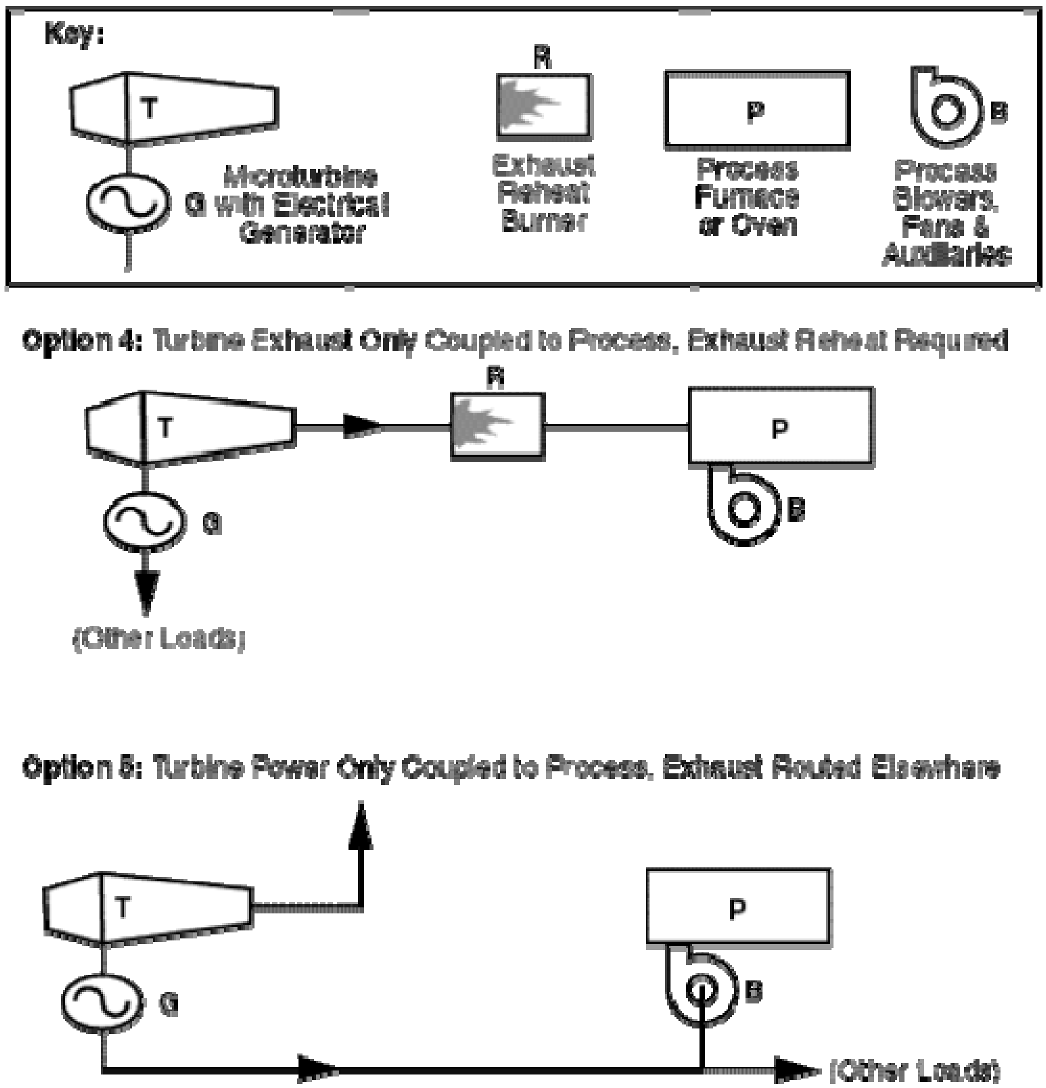


Figure 37: Microturbine Process Heating/Power Options 4-5



5.2 Microturbine Exhaust-to-Process Options

There are six possible ways to couple the microturbine exhaust to the fired process, as shown on Figure 38, Figure 39, and Figure 40. Advantages and disadvantages of each method are pointed out. From the standpoint of initial cost, adaptability to the greatest number of processes, and minimal interference with the operation of the turbine, Option 4 is the most desirable.

Figure 38: Microturbine Exhaust to Process Options 1-2

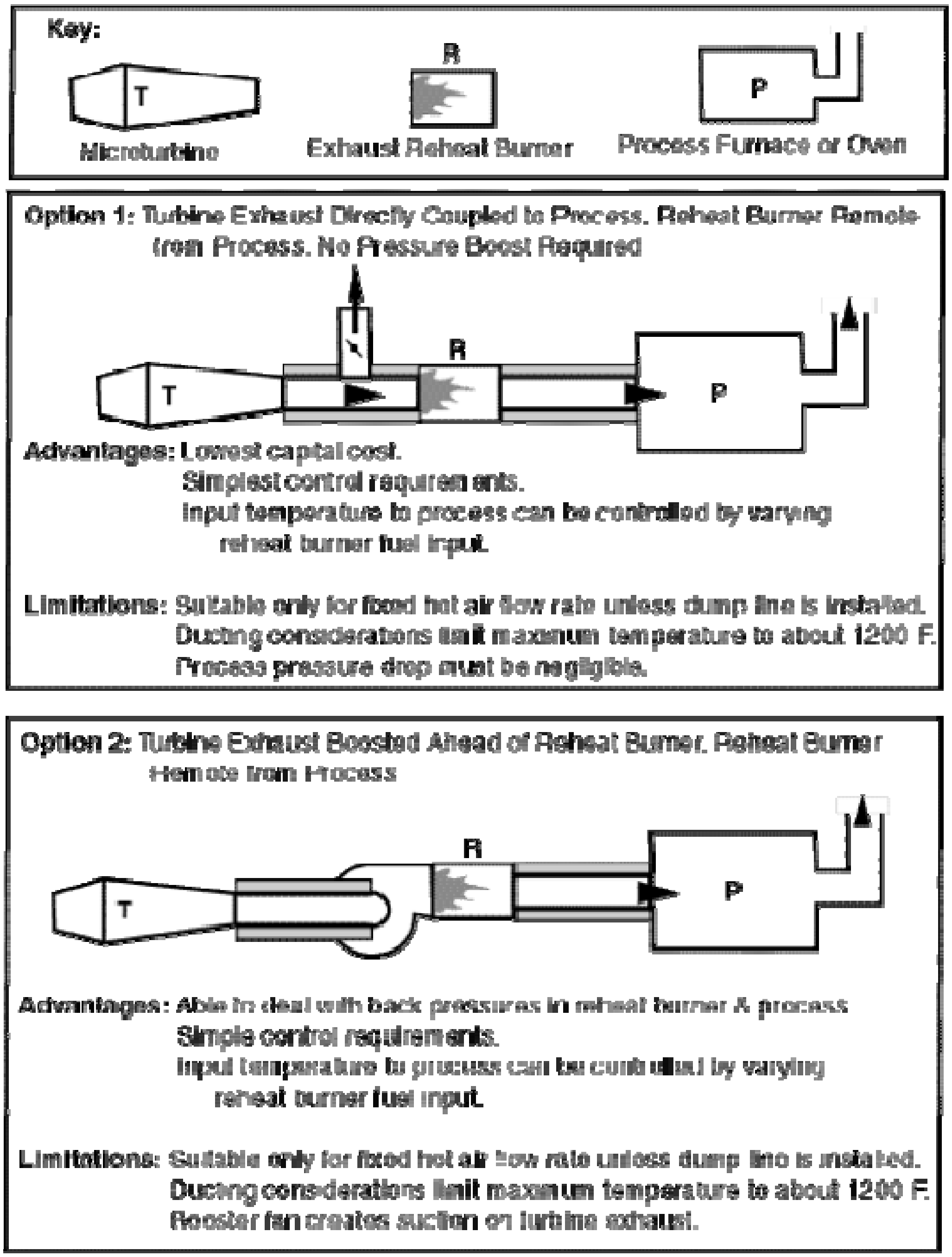


Figure 39: Microturbine Exhaust to Process Options 3-4

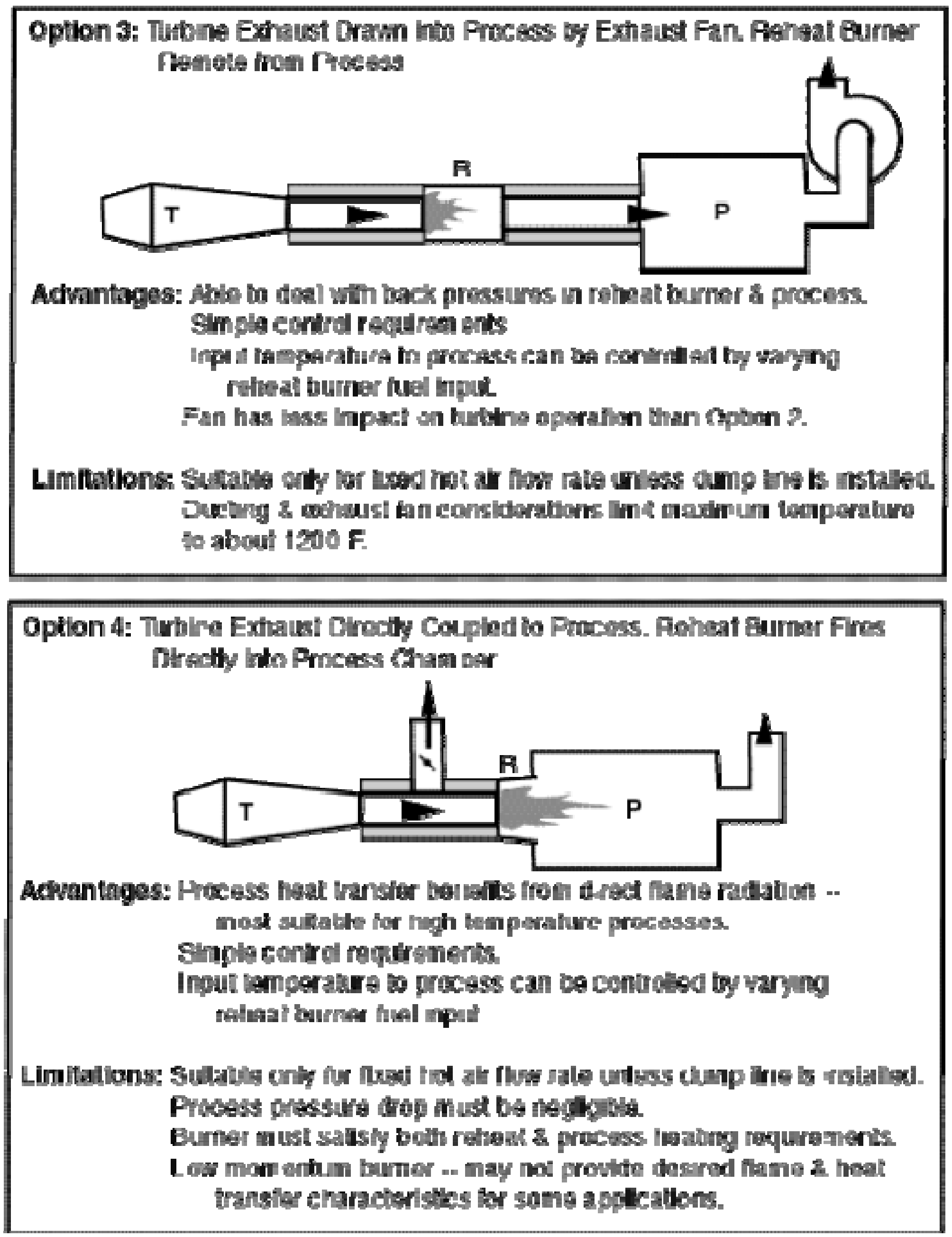
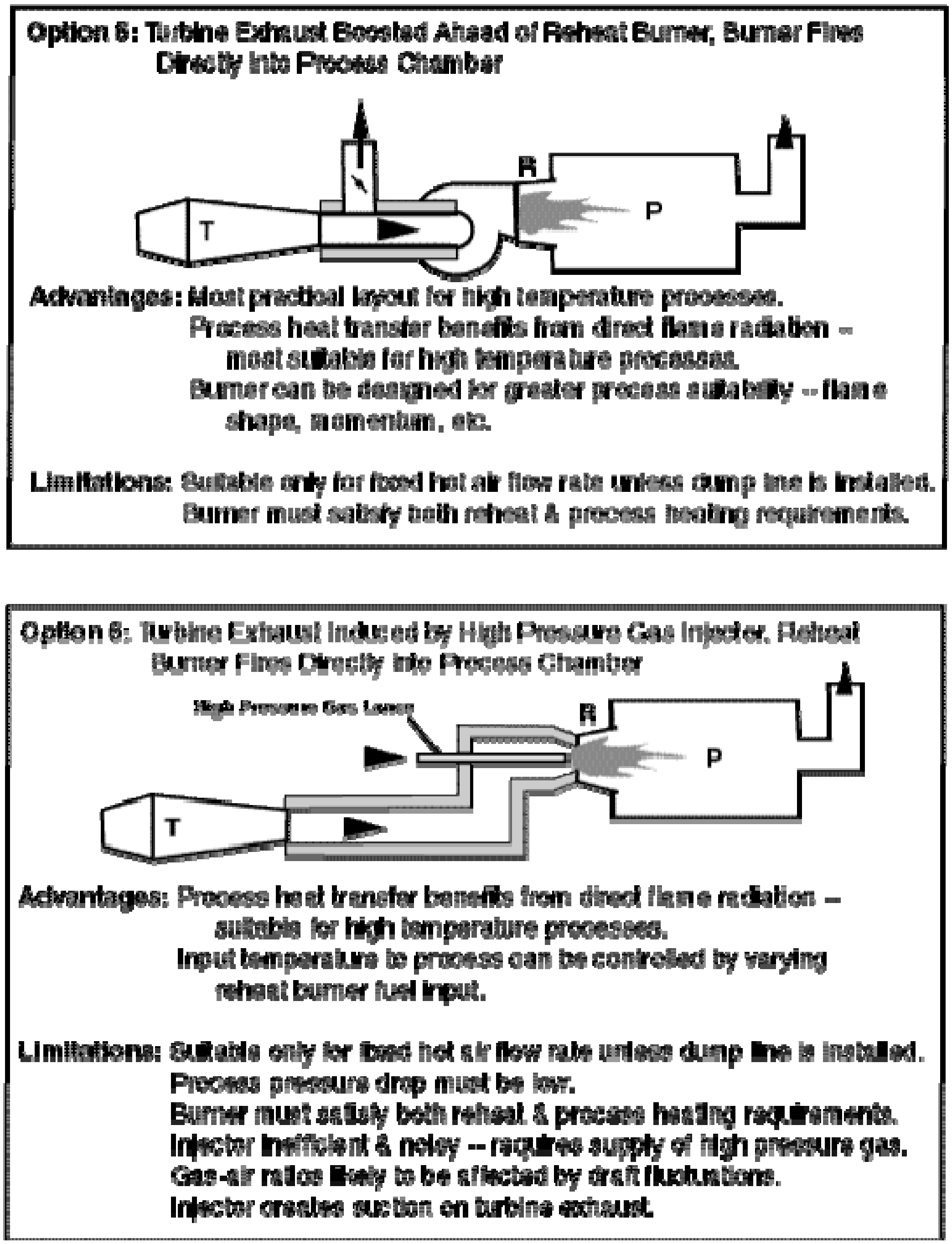


Figure 40: Microturbine Exhaust to Process Options 5-6



CHAPTER 6: Conclusions

The CARB 2007 Fossil Fuel Emissions Standard for integrated CHP installations is 0.07 lb/MWh. GTI's application of the supplemental ULN burner to a heat recovery boiler using the exhaust gas from a gas turbine exceeds the new standard. Earlier developmental work proved that the exhaust gas from a 60-kW microturbine produces enough oxidant at its full capacity to fire a natural gas burner to approximately 2.2 million Btu/h input. The exhaust temperature from the microturbine was approximately 580°F and added approximately 0.3 million Btu/h of heat to the boiler for a total input of 2.8 million Btu/h.

As a continuation of the earlier developmental work, the burner technology was scaled to 7.5 million Btu/h. At this firing capacity, the microturbine was not capable of generating sufficient Turbine Exhaust Gas (TEG) at temperature to simulate the Mercury 50 gas turbine. An auxiliary burner was used to generate flue gases that were mixed together with dilution air. The resulting mixture closely matched the gas composition and temperature of the Mercury 50 gas turbine across its firing range.

The results from laboratory evaluation of the 7.5 million Btu/h supplemental burner show comparable performance to that of the smaller unit. The burner was capable of adding significant thermal energy to the Simulated Turbine Exhaust Gas (STEG) while contributing little additional NOx emissions at the stack. On a volume per volume basis, stack NOx emissions, after supplemental firing, were lower than NOx emissions from the gas turbine. The burner also demonstrated the ability to handle large differences in excess air from 20 to 280 percent. This is important when minimal heat is required and the gas turbine is producing the maximum amount of exhaust.

Following development activities, the supplemental ULN burner was integrated into a flexible, pre-engineered CHP system, termed FlexCHP, which combines a Capstone C65 microturbine, a 100 HP heat recovery boiler by Johnston Boiler Company, and custom controls package. Demonstration of the FlexCHP performance at GTI facilities showed the system capable of exceeding CARB 2007 emissions criteria for NOx, CO, and THC across full turndown in supplemental burner firing rate.

The FlexCHP system was installed at a food processing facility, Inland Empire Foods Inc., located in Riverside, California to meet facility electrical and steam demands. The microturbine was set to operate at full load capacity providing a net electrical output of 60 kWe. Under these conditions the exhaust exits the turbine at 615 °F with 17.8 % O_2. With the supplemental burner operating at full fire capacity (2.7 million Btu/h), the final stack conditions were 233 °F with 6.6 percent O_2. This reduction in exhaust temperature and oxygen content allowed for a substantial gain in heat recovery, boosting overall system efficiency to 82.4 percent.

The FlexCHP system demonstrated significant improvements in performance, both in terms of efficiency and emissions as compared to the microturbine operating alone (Table 11). System efficiency is increased from 23.6 percent to 82.4 percent or 84.2 percent based upon the measurement method, by recovering heat from the turbine exhaust to generate steam at rates up to 2,140 lb/h. Under full load conditions, NOx, CO, and THC emissions are reduced by 45 percent, 97 percent, and 78 percent, respectively.

Table 11: Field Performance of FlexCHP System versus Microturbine

Parameter	Microturbine	FlexCHP (full load)
Efficiency [%]	23.6	82.4[a] to 84.2[b]
Steam Output [lb/h]	0	2,140
Net Electricity Output [kWe]	60	60
Exhaust Temperature [°F]	615	233
Oxygen [%]	17.8	6.6
NOx @ 15% O_2 [vppm]	4.0	2.2
CO @ 15% O_2 [vppm]	6.6	0.2
THC @ 15% O_2 [vppm]	0.9	0.2

a – input/output method, b – turbine and boiler losses method

The field demonstration tests have proven the system capable of meeting CARB 2007 emissions criteria across full turndown in supplemental burner firing rate. Under optimal conditions, NOx emissions are 0.035 lb/MW-h, which is half of the required 0.07 lb/MW-h. Similarly, the CO and THC emissions are near zero at high fire conditions, providing values far below the required 0.10 and 0.02 lb/MW-h required.

By integrating the microturbine, supplemental burner, and heat recovery boiler into a single package that recovers the heat in the microturbine exhaust, the FlexCHP system delivers increased efficiency and reduced emissions in comparison to a boiler and microturbine operating independently to deliver the same quantity of thermal energy and electricity. If an independent boiler were utilized for thermal energy production and it were operated with the same stack conditions as those of the FlexCHP (233 °F, 6.6 percent O_2), a boiler efficiency of 84.2 percent could be achieved (based on flue gas and estimated boiler jacket losses). Using this efficiency, a boiler firing rate of 3.2 million Btu/h would be required to achieve the same thermal output as that achieved by the FlexCHP system (2.7 million Btu/h). If the microturbine were operated independent of the boiler under the same conditions as those at the demonstration site, it would achieve 59.6 kWe output for 0.86 million Btu/h fuel input, yielding an efficiency of

23.6 percent. Thus, the overall efficiency for a plant operating with a separate boiler and microturbine as described here would be 71.3 percent (based on a weighted average of boiler and microturbine efficiencies weighted by their respective firing rates). Thus, the FlexCHP system provides a substantial increase in overall efficiency as compared to the boiler and microturbine operating independently without adding equipment cost. Moreover, the total mass flow rate of pollutants is reduced since the TEG emissions levels are reduced by the supplemental burner and the overall flue gas mass flow is less for the FlexCHP packaged system.

Benefits to California: This project has successfully designed and demonstrated a high-efficiency CHP system capable of using a small to medium sized gas turbine for new and retrofit applications in the range of 30 to 5500 kW, and which meets the CARB 2007 emissions standard. Targeted for boilers and absorption chillers, the technology will reduce the capital cost of Distributed Generation (DG) /CHP systems by 10 to 25 percent. This will make DG/CHP systems more acceptable to small to medium size (10 MW or less) industrial plants and commercial buildings, representing a large portion of the available California market. The project supports California's policy goals by: increasing efficiency in all of the state's energy sectors; encouraging the development of environmentally-sound CHP resources and distributed generation projects; and supporting the reduction of greenhouse gases.

ACRONYMS

ASERTTI-Association of State Energy Research and Technology Transfer Institutions

CARB-California Air Resource Board

CHP-Combined Heat and Power

CO-Carbon Monoxide

CO_2-Carbon Dioxide

FlexCHP-Flexible Combined Heat and Power

GTI-Gas Technology Institute

HHV-High Heating Value

HP-Horse Power, Boiler

NOx-Nitrogen Oxides

O_2-Oxygen

SCAQMD-South Coast Air Quality Management District

SCR-Selective Catalytic Reduction

STEG-Simulated Turbine Exhaust Gas

TEG-Turbine Exhaust Gas

THC-Total Hydrocarbons

ULN-Ultra-Low-Nitrogen Oxides

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3. Kaarsberg, T., R.N. Elliott, and M. Spurr, "An Integrated Assessment of the Energy Savings and Emissions-Reduction Potential of Combined Heat and Power." Proc. ACEEE 1999 Industrial Summer Study, Washington DC, 1999.